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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB BURNS – Chairman
BOYD DUNN
SANDRA D. KENNEDY
JUSTIN OLSON
LEA MÁRQUEZ PETERSON

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-19-0236 **NOTICE OF FILING DIRECT TESTIMONY (REVENUE REQUIREMENT) AND EXHIBITS OF KEVIN C. HIGGINS ON BEHALF OF FREEPORT MINERALS CORPORATION AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION**

Freeport Minerals Corporation and Arizonans for Electric Choice and Competition (collectively "AECC") hereby submit the Direct Testimony (Revenue Requirement) and Exhibits of Kevin C. Higgins on behalf of AECC in the above-captioned docket.

For the parties who have signed the Arizona Public Service Company ("APS") Protective Agreement, they will be able to view the confidential portion of Mr. Higgins' Exhibits (Confidential Exhibit KCH-16) by accessing the APS Rate Case website.

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FENNEMORE CRAIG
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RESPECTFULLY SUBMITTED this 2nd day of October, 2020.

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-19-0236

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport Minerals Corporation and

Arizonans for Electric Choice & Competition

Revenue Requirement

October 2, 2020

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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EXHIBITS (CONTINUED)

DIRECT TESTIMONY OF KEVIN C. HIGGINS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport Minerals Corporation and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

[1] Henceforth in this testimony, Freeport Minerals Corporation and AECC collectively will be referred to as "AECC."

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you testified before this Commission in other dockets?

A. Yes. I have testified in approximately 25 proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on the Arizona Public Service Company ("APS") 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico 2004 rate case (2005),[10] the TEP 2004 rate review (2005),[11] the APS 2006 interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13] TEP's request to amend Decision No. 62103 (2007),[14] the TEP 2007 rate case

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[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.
[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.
[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.
[13] Docket No. E-01345A-05-0816.
[14] Docket No. E-01933A-05-0650.

(2008),[15] the APS 2008 rate case (2008),[16] the APS 2011 rate case (2011-12),[17] the TEP 2011 Energy Efficiency Plan (2012),[18] the TEP 2012 rate case (2012),[19] the APS Four Corners Rate Rider proceeding (2014),[20] the UNSE Electric, Inc. ("UNSE") 2015 rate case (2015),[21] the TEP 2015 rate case (2015),[22] the TEP 2015 rate case Phase II proceeding (2018),[23] the APS 2016 rate case (2016 and 2018),[24] and the TEP 2019 rate case (2020).[25]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 225 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission.

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[15] Docket No. E-01933A-07-0402.
[16] Docket No. E-01345A-08-0172.
[17] Docket No. E-01345A-11-0224.
[18] Docket No. E-01933A-11-0055.
[19] Docket No. E-01933A-12-0291.
[20] Docket No. E-01345A-11-0224.
[21] Docket No. E-04204A-15-0142.
[22] Docket No. E-01933A-15-0322.
[23] *Id.*
[24] Docket Nos. E-01345A-16-0036 & E-01345A-16-0123.
[25] Docket No. E-01933A-19-0028.

II. OVERVIEW AND CONCLUSIONS

Q. What is the purpose of your testimony in this phase of the proceeding?

A. My revenue requirements testimony addresses three major topics:

(1) APS's stated request for a net revenue increase of $184 million, consisting of a base revenue increase of $69 million and adjustor transfers of $115 million;

(2) APS's request for deferred accounting treatment for its Arizona property taxes; and

(3) The formula rate concept introduced in this proceeding by APS.

Absence of comment on my part regarding a particular issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that APS's revenue requirement increase be reduced by at least $121.212 million relative to the $184 million net increase to customer rates presented by APS in its direct testimony. This reduction does not take into account any reasonable adjustments that may be offered by other parties that are not addressed in my direct testimony.

(2) I recommend that APS's request for a deferral mechanism for its property tax expense be denied.

(3) While APS has not proposed a formula rate in this filing, APS witness Mr. Leland R. Snook introduces a "formula prototype" for the Commission's consideration.[26] I recommend that the formula prototype be rejected by Commission. APS's formula rate concept, in which annual rate adjustments would be implemented based on updating formula inputs, would not allow for the same level of scrutiny as is possible in a general rate case proceeding. As my testimony will underscore, synchronizing the revenue, expense, and rate base components of the revenue requirement is a complex exercise that is best undertaken in the context of a general rate case.

III. ADJUSTMENTS TO REVENUE REQUIREMENT

Q. What increase in revenues is APS requesting in this case?

A. In its Application, APS is requesting a $184 million net revenue increase. This request includes a base rate revenue increase of $69 million and several adjustor transfers: (1) a net decrease to the Tax Expense Adjustor Mechanism ("TEAM") of $119.3 million; (2) the transfer of $3.9 million of environmental compliance revenue requirements presently collected in the Environmental Improvement Surcharge to base rates; and (3) the transfer of $321,000 of Arizona Solar Communities-related costs from the Renewable Energy Adjustment Charge to base rates.[27]

[26] Direct Testimony of Leland R. Snook, pp. 22-24.
[27] Direct Testimony of Leland R. Snook, pp. 2-3.

Q. Do you have any recommended adjustments to APS's proposed revenue requirement increase?

A. Yes. I am recommending a reduction of at least $121.212 million to the $184 million net increase to customer rates presented by APS in its direct testimony. This reduction includes an illustrative reduction to APS's requested return on equity ("ROE") from 10.15% to 9.75%, which is the median ROE approved by state regulators in the United States for vertically-integrated electric utilities as reported by Regulatory Research Associates, a group within S&P Global Market Intelligence, for the 12-month period ended June 30, 2020. My recommended net revenue requirement adjustments are summarized in Table KCH-1, below.

Table KCH-1
Summary of AECC Adjustments to APS Net Revenue Requirement ($000)

Net Impact

	Adjustment Impact	Increase/ (Decrease)
APS - As Filed Requested Base Revenue Increase		$ 68,591
Less Impact of Rider Revenue Transferred to Base Rates		$ (115,042)
APS Requested Increase – Net		$ 183,633
AECC Recommended Adjustments		
Post TY Plant Avg RB Adjustment	(37,881)	145,752
Post TY Plant Depreciation & Prop. Tax Expense Adj.	(22,799)	122,953
Existing Plant Avg RB Adjustment	27,035	149,988
West Phx 4 Avg RB Adjustment	15	150,003
Recent Deferrals Average RB Adjustment	(2,093)	147,910
Pension & OPEB RB Adjustment	(22,141)	125,769
Pension & OPEB Expense Adjustment	(12,852)	112,917
Pro Forma Test Year Payroll Expense Adjustment	(1,458)	111,459
Cash Incentive Expense Adjustment	(20,362)	91,097
Customer Annualization Adjustment	(2,261)	88,836
Return on Equity	(23,855)	64,981
Navajo Plant Regulatory Asset Return Adjustment	(2,560)	62,421
AECC Adjustment Total	$ (121,212)	

Q. Do you propose any other adjustments relative to APS's proposed base rate increase?

A. Yes. In addition to the adjustments in Table KCH-1, above, I recommend that the $20 million of Demand Side Management ("DSM") expenses currently recovered in base rates be transferred to the DSM Adjustment Charge ("DSMAC"). While this will reduce base rates by approximately $20 million, it will not impact the net revenue increase because it is revenue neutral on an overall basis. I will discuss this recommendation in greater detail in my rate design testimony, but I include the adjustment here due to its impact on the base rate revenue requirement.

My recommended base revenue requirement adjustments are presented in Exhibit KCH-1 and are summarized in Table KCH-2, below. Each of my adjustments will be discussed in turn.

Table KCH-2
Summary of AECC Adjustments to APS Base Revenue Requirement ($000)

Base Rate Impact

	Adjustment Impact	Increase/ (Decrease)
APS - As Filed Requested Base Revenue Increase		**$ 68,591**
AECC Recommended Adjustments		
Post TY Plant Avg RB Adjustment	**(37,881)**	**30,710**
Post TY Plant Depreciation & Prop. Tax Expense Adj.	**(22,799)**	**7,911**
Existing Plant Avg RB Adjustment	**27,035**	**34,946**
West Phx 4 Avg RB Adjustment	**15**	**34,961**
Recent Deferrals Average RB Adjustment	**(2,093)**	**32,868**
Pension & OPEB RB Adjustment	**(22,141)**	**10,727**
Pension & OPEB Expense Adjustment	**(12,852)**	**(2,125)**
Pro Forma Test Year Payroll Expense Adjustment	**(1,458)**	**(3,583)**
Cash Incentive Expense Adjustment	**(20,362)**	**(23,945)**
Customer Annualization Adjustment	**(2,261)**	**(26,206)**
Return on Equity	**(23,855)**	**(50,061)**
Navajo Plant Regulatory Asset Return Adjustment	**(2,560)**	**(52,621)**
Transfer DSM Expense to DSMAC Adjustment	**(20,000)**	**(72,621)**
AECC Adjustment Total	**$ (141,212)**	

Test Period Issues

Q. What is meant by the term "test year" as used in ratemaking?

A. "Test year" refers to a discrete twelve-month period that is used as the basis for setting utility rates in a general rate proceeding. This term is often used interchangeably with the term "test period," although some jurisdictions make a fine distinction between the two, with "test year" referring to the baseline period for which underlying historical financial and operating data must be reported and "test period" referring to the twelve-month period used for setting rates. When this distinction is made, test year and test period can be coterminous, overlapping, or entirely distinct time periods.

Q. What test year is APS using in its application?

A. Nominally, APS is proposing to use the 12-month period ending June 30, 2019 as its test year for revenue requirement purposes. As such, APS begins its analysis by presenting a baseline that sets out the Company's revenue, expense, and investment levels for the July 1, 2018 to June 30, 2019 period. These results are then adjusted for ratemaking purposes, which is typical in most general rate proceedings. However, in APS's filing, the adjustments to the historical test year are "brought forward" quite significantly. While the basis of the Company's filing generally starts with actual revenues, expenses, and investment for the 12-month period ended June 30, 2019, the filing incorporates various revenue, expense, and investment elements that are adjusted for values that either occurred or are projected to occur variously in 2019 or 2020.

For example, APS includes $756.3 million of gross post-test year plant that is projected to be added through June 30, 2020 in ACC jurisdictional rate base.[28] Significantly, APS proposes to value this plant for ratemaking purposes at its *end-of-period* value (i.e., on June 30, 2020), thus reflecting its value at the start of the period from July 1, 2020 through June 30, 2021. Similarly, depreciation expense is annualized using the projected plant balances on June 30, 2020, and thus reflects the depreciation expense projected for the post-test year plant for the period from July 1, 2020 through June 30, 2021, rather than the (significantly lower) depreciation expense that is actually incurred for the post-test year plant for the prior year, July 1, 2019 through June 30, 2020.

Yet another example is payroll expense. APS first annualizes its payroll expense to the level incurred in the final quarter of the test year ended June 30, 2019.[29] Then, the Company adds a union wage increase projected for April 1, 2020 at its full 12-month value.[30]

While APS's "adjusted test period" defies a clear and consistent description with respect to the time period it depicts, in many respects it most reflects an effective test period for ratemaking of July 1, 2019 to June 30, 2020, measured at the end of period.

Q. What do you mean by an "effective" test period for ratemaking?

A. By "effective" test period, I am referring to the test period that is actually being used for ratemaking purposes after adjustments are taken into account. As I stated above, nominally APS is using a test year based on the 12-month period ended

[28] Derived from APS Schedule B-2.
[29] See EAB-WP35DR IS – Annualize Payroll Pro Forma.
[30] See APS's response to Data Request AECC 8.7, included in Exhibit KCH-15.

June 30, 2019. But after adjustments, it most closely resembles a test period covering July 1, 2019 through June 30, 2020. Furthermore, by using end-of-period rate base and annualizing expenses to end-of-period levels, rate base and expense for items providing service on June 30, 2020 are set at the starting level for the *subsequent* year.

Q. But isn't APS supposed to be using an *historical* test year for setting rates?

A. R14-2-103 defines test year as "the one-year historical period used in determining rate base, operating income and rate of return." While R14-2-103 allows for pro-forma adjustments to actual test year results and balances to obtain a normal or more realistic relationship between revenues, expenses, and rate base, the rule also states that "the end of the test year shall be the most recent practical date available prior to the filing." While I can offer no legal opinion on this language, one possible interpretation is that only historical test periods may be used to set rates in an APS rate case.

However, each of the last several APS rate cases have featured substantial post-test period plant additions measured at end-of-period values, as well as annualizations of expense items that go well beyond the end of the nominal test period – in this proceeding 12 months beyond. Based on my experience in ratemaking, I would characterize the effective test period used by APS to be a fully projected test period at the time of its filing in October 2019. Legal questions aside, a key policy question then is: how aggressively-forward should the effective test period be allowed to be relative to the historical test year? In my opinion, if APS is permitted to recognize rate base and expense adjustments extending a full 12 months beyond the end of its historical test period, as the Company is requesting, then it is more appropriate to measure these items at their average-of-period values rather than at their end-of-period values.

Q. Why do you believe that APS should not be allowed to measure its post-test year rate base and expenses at their end-of-period values?

A. The sole justification for using an end-of-period rate base is to address utility concerns about regulatory lag. According to the regulatory lag argument, utilities are challenged to earn their authorized rates of return on investment during periods of system expansion when historical test periods are used for setting rates. One means of reducing regulatory lag is to use a projected test period – or in this instance, an adjustment for projected plant additions – rather than a strictly historical measurement period. An entirely separate means of reducing regulatory lag is to adjust rate base in an historical test period to an end-of-period value, as this will cause the utility's authorized rate of return to be applied to the year-ending value of net plant in service. However, in offering its plant additions adjustments, APS proposes to combine both a projected measurement period and an end-of-period rate base. This "doubling up" of regulatory lag mitigation approaches is unreasonably aggressive.

In contrast, a less aggressive and more reasonable approach would value the post-test period plant on an *average* basis, calculated using the average monthly value of the new plant as it was projected to be added over the course of the period July 1, 2019 through June 30, 2020. This latter approach is known as "average-of-period" rate base. In my opinion, an average of period rate base is more reasonable and appropriate when using a projected test period (i.e., a test period that ends in the future relative to the filing date of the rate case).

Q. The procedural schedule for this case has been delayed. Does that delay justify using an end-of-period effective rate base?

A. I do not believe so. I acknowledge that the delay in the schedule of this case has caused the historical test period to recede further into the past. Yet the fact remains that APS filed its case seeking an additional 12 months of post-test-period plant additions on a projected basis. I believe the most appropriate measurement for a projected rate base is average-of-period value. Since the value of rate base changes each month as new plant is added and existing plant depreciates, determining rate base by averaging each month's value ensures that the asset base upon which the utility will earn a return is reflective of its "typical" value during the course of the effective test period ending June 30, 2020.

Later in my testimony, I recommend adjustments to revenue and expenses based on the amounts projected to be experienced during an effective test period July 1, 2019 to June 30, 2020.

Q. Have you prepared an adjustment that converts APS's end-of-period rate base into an average-of-period value?

A. Yes, I have. This adjustment has multiple components that are necessary to reflect the average rate base balance and associated expenses for the 12 months ending June 30, 2020:

- Post-Test Year Plant Average Rate Base Adjustment;
- Post-Test Year Plant Depreciation Expense & Property Tax Adjustment;

- Existing Plant Average Rate Base Adjustment;
- West Phoenix 4 Average Rate Base Adjustment; and
- Recent Deferrals Average Rate Base Adjustment.

Q. Please explain the Post-Test Year Plant Average Rate Base component of this adjustment.

A. This component of the adjustment reflects the impact of calculating the rate base (gross plant, accumulated depreciation, and accumulated deferred income taxes ["ADIT']) associated with post-test year plant additions based on the 13-month average balance for the period June 2019 through June 2020. This component of my adjustment is presented in Exhibit KCH-2. I estimate that it reduces APS's retail revenue requirement by **$37.881** million.

Q. Please explain the Post-Test Year Plant Depreciation Expense and Property Tax component of this adjustment.

A. This component of the adjustment represents the estimated impact of calculating depreciation expense and property tax expense based on the 13-month average post-test year plant balance for the period June 2019 through June 2020, rather than the balance as of June 30, 2020 used by APS. This component of my adjustment is presented in Exhibit KCH-3. I estimate that it reduces APS's retail revenue requirement by **$22.799** million.

Q. What is the Existing Plant Average Rate Base component of this adjustment?

A. This component of the adjustment includes the impact of calculating accumulated depreciation and amortization on existing plant based on the 13-month average balance for the period June 2019 through June 2020, rather than the balance as of

June 30, 2020 used by APS. Since accumulated depreciation and amortization is a reduction to rate base, this component of my adjustment incrementally increases the revenue requirement. Also included in this component of the adjustment is the estimated impact of calculating ADIT associated with existing plant based on the average balances for June 2019 and June 2020. This component of my adjustment is presented in Exhibit KCH-4. I estimate that it increases APS's retail revenue requirement by **$27.035** million.

Q. Please explain the West Phoenix 4 Average Rate Base component of this adjustment.

A. APS includes an adjustment to reduce rate base to reflect the West Phoenix 4 regulatory disallowance in its revenue requirement. In that adjustment, the gross West Phoenix 4 plant balance is represented as a negative amount, offset by accumulated amortization and ADIT as of June 30, 2019.[31] This component of my adjustment calculates the accumulated amortization and ADIT based on the average balances for June 2019 and June 2020, which results in a small incremental increase to the revenue requirement. This component of my adjustment is presented in Exhibit KCH-5. I estimate that it increases APS's retail revenue requirement by **$15 thousand**.

Q. What is the Recent Deferrals Average Rate Base component of this adjustment?

A. In the Settlement Agreement in APS's last rate case, APS was permitted to defer costs associated with several items: changes to the Arizona composite property tax rate, the Ocotillo Modernization Project, and Four Corners Selective Catalytic

[31] EAB-WP9DR RB – WPhx4 Disallowance Pro Forma.

Reduction equipment.[32] APS includes adjustments to its rate base to reflect the projected December 31, 2020 balances associated with these items, and simultaneously includes the amortization expense necessary to amortize these balances over ten years.[33]

Since APS includes the annual amortization expense associated with these deferred balances on a going-forward basis, it is appropriate to reflect the offsetting reduction to these balances that will occur through amortization. However, APS includes these deferred balances at their beginning values, prior to any amortization taking place.

This component of my adjustment reflects the average unamortized balance of these deferrals during the first year of amortization. That is, I reduced the regulatory assets/liabilities by one-half the annual amortization expense associated with these deferred balances. I also included the offsetting impact of ADIT associated with my adjustment to these regulatory assets/liabilities. This component of my adjustment is presented in Exhibit KCH-6. I estimate that it decreases APS's retail revenue requirement by **$2.093** million.

Pension & Other Post-Employment Benefits ("OPEB") Assets/Liabilities Adj.

Q. By way of introduction, how does APS recover its pension and OPEB costs?

A. APS is afforded recovery of its pension and OPEB costs based on the "net periodic benefit cost" included in its revenue requirement in general rates cases.

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[32] Docket Nos. E-01345A-16-0036 and E-01345A-16-0123, Decision No. 76295, IV. f., g., h at 22-23.
[33] See EAB-WP10DR RB - Include Property Tax Deferral, EAB-WP12DR RB - Ocotillo Deferral Pro Forma, EAB-WP13DR RB - Four Corners SCR Deferral Pro Forma, EAB-WP26DR IS - Four Corners SCR Deferral Pro Forma, EAB-WP27DR IS - Ocotillo Deferral Pro Forma, and EAB-WP42DR IS - PTAX Deferral Pro Forma.

For ratemaking purposes, net periodic benefit cost is comprised of pension and OPEB expense (i.e., benefit costs being expensed during a rate case test year) and capitalized pension and OPEB costs (i.e., test period benefit costs that are not expensed in the rate case test year, but are rolled into rate base). Thus, in a ratemaking context, "net periodic benefit cost" is what customers are charged for the Company's annual pension and OPEB costs. However, as is the case with ratemaking generally, once this amount is established in a rate case, it remains set until the next general rate case, even though the annual net periodic benefit cost actually experienced by the utility will change from year to year.

The components generally included in the net periodic benefit cost are shown in Table KCH-3, below.

Table KCH-3
Components of Net Periodic Benefit Cost

	Service Cost
+	Interest Cost
-	Expected Return on Plan Assets
+/-	Amortization of Prior Period Service Cost
+/-	Amortization of Actuarial Gains/Losses
=	Annual Net Periodic Benefit Cost

Q. Are an employer's annual cash expenditures for its pension and OPEB plans and net periodic benefit costs the same?

A. Generally, no. Employer contributions often differ from the net periodic benefit cost recognized in any given year, although over the life of the pension and OPEB plans, the total employer contributions and the cumulative net periodic benefit cost are equal.

The actual amount the Company contributes to its pension plans each year is a corporate policy decision which is subject to federal statutes. These statutes govern the maximum contribution that can be immediately deducted for tax purposes and the minimum contribution required to satisfy plan funding rules.[34] The Company has discretion over the actual amount contributed to its pension plans each year subject to these statutes.

OPEB plans are not subject to the same federally mandated minimum funding requirements as pension plans but are subject to funding limits and deductibility rules.

Q. Does APS include regulatory assets or liabilities associated with its pension and OPEB plans in rate base?

A. Yes, there are several items related to the Company's pension and OPEB plans that APS includes in rate base. A list of these items is presented in Table KCH-4, later in my testimony. As I will explain below, I do not believe that APS's inclusion of these items in rate base has been properly vetted and I recommend they be removed from rate base. One of these items is a pension asset associated with unrecognized actuarial losses, which I will discuss first. The unrecognized actuarial loss pension asset totals $712.9 million on a Total Company basis and $654.4 million on an ACC jurisdictional basis as of June 30, 2019.[35]

Q. What is an unrecognized actuarial loss or gain?

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[34] The principal statues are the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006. Section 401(a) of the Internal Revenue Code sets out the requirements for a qualified pension plan.

[35] See EAB-WP5DR Schedule B-1, Reg Asset Liab tab, line 1 and APS's response to Data Request AECC 10.1, included in Exhibit KCH-15.

A. Unrecognized actuarial losses and gains represent the cumulative adjustments to the value of pension or OPEB plan assets and liabilities that have not yet been reflected in earnings through the net periodic benefit cost. In any given year, actual experience will generally differ from the long-term assumptions used to set the net periodic benefit cost.[36] For example, the actual return on plan assets may be lower than the expected long-term return included in the net periodic benefit cost, resulting in a loss. Losses and gains can also result from changes in actuarial assumptions.

Immediately recognizing changes to the actuarial valuation in earnings could result in earnings volatility for the employer sponsoring the plan. Therefore, employers, including utilities, are not required to immediately recognize these changes to the value of pension or OPEB plan assets or liabilities in net periodic benefit cost. Instead, such gains or losses can generally be reflected as increases or decreases to "other comprehensive income," which is excluded from net income.[37] It is possible that, over time, gains and losses may offset each other, but a portion of the net gain or loss is required to be amortized (i.e., recognized in earnings) if a "corridor" of materiality is exceeded.[38] The annual amortization of such losses is included as a component of net periodic benefit cost as shown in Table KCH-3, above.

Q. When must previously unrecognized losses or gains be included in the net periodic benefit cost?

[36] See Accounting Standards Codification ("ASC") 715-30-35-22- ASC 715-30-35-23. The Financial Accounting Standards Board ASC can be accessed for free using Basic View available at https://asc.fasb.org/.
[37] ASC 715-30-35-21; ASC 715-60-35-25.
[38] The corridor rule was first established in FASB Statement No. 87 (December 1985).

A. At a minimum, amortization of a net gain or loss must be included as a component of net periodic benefit cost for a year if the net gain or loss exceeds 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets. The minimum amortization required is the excess divided by the average remaining service life of active employees expected to receive benefits, or, if most employees are inactive, over the remaining life expectancy of the employees.[39]

This approach allows the recognition of losses or gains in earnings to be smoothed out over a long period of time.

Q. Does APS's net periodic pension cost include the amortization of unrecognized losses?

A. Yes. According to the Willis Towers Watson September 2019 Actuarial Valuation Report for Pinnacle West's qualified pension plan, $37.9 million was included in 2019 pension cost for amortization of net losses.[40] Approximately $26.9 million of this amortization of net losses was charged to APS expense, and about $24.7 million of that amount is ACC jurisdictional.[41]

Q. Do unrecognized actuarial losses represent a cash expenditure made by APS?

A. No. Unrecognized losses represent changes to the valuation of APS's pension and OPEB plan assets or liabilities that have not yet been reflected in net periodic

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[39] ASC 715-30-35-24; ASC 715-60-35-29.

[40] Initial 1.48_APS19RC00269_2019 Retirement Report_CONF, excerpted in Confidential Exhibit KCH-16.

[41] Based on EAB-WP36DR IS – Normalize Employee Benefits Pro Forma, Jan-Dec 2019 tab, approximately 71% of the Non-Service Cost w/o SEBRP PNW and OPEB ROA total is charged to APS expense. According to Schedule C-2, approximately 91.8% of APS's Normalize Employee Benefits adjustment is ACC jurisdictional.

benefit cost. Not only are unrecognized actuarial losses not a cash expense – they have not yet even been reflected in earnings through net periodic benefit cost.

Q. If unrecognized losses are not a cash expenditure, what reason does APS provide for including unrecognized losses as a regulatory asset?

A. APS explains that Generally Accepted Accounting Principles ("GAAP") traditionally require that unamortized actuarial losses be recorded as a loss in other comprehensive income. However, Statement of Financial Accounting Standards ("FAS") No. 71 allows a regulated utility to instead establish a regulatory asset to record actuarial losses.[42]

According to Pinnacle West's 2019 10-K, "This asset represents the future recovery of pension benefit obligations through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI [other comprehensive income] and result in lower future revenues."[43]

Apparently, APS has chosen to reflect unrecognized actuarial losses as a regulatory asset because APS has determined that recovery of this balance in future rates is probable.

Q. Do you agree that recovery of unrecognized actuarial losses in future rates is probable?

A. Yes. As I explained previously, unrecognized losses or gains are gradually included the net periodic benefit cost when the balance exceeds a given threshold. It is possible that actuarial losses and gains may offset each other over time, but in concept, I agree that unrecognized losses will generally be included in future net

[42] See APS response to Data Request AECC 10.1 e., included in Exhibit KCH-15.
[43] Form 10-K For the fiscal year ended December 31, 2019, page 122, footnote (a).

periodic benefit cost, which is a component of APS's revenue requirement established in rate cases.

Q. Does this mean you agree that customers should pay APS a return on its unrecognized actuarial losses?

A. No. Unrecognized actuarial losses do not represent a cash outlay by APS, so it is inappropriate for customers to pay a carrying charge on this balance. I do not object to APS treating unrecognized actuarial losses as a regulatory asset, but the asset should not be included in rate base and earn a return.

Q. Has the Commission explicitly determined that unrecognized actuarial losses should be included in rate base as a regulatory asset?

A. Not to my knowledge. In discovery, APS contends that Commission precedents allow APS to include the pension asset as a regulatory asset, based on Decision Nos. 69663, 71448, 73183, and 76295.[44] However, APS did not file any testimony in those dockets seeking to include unrecognized actuarial losses in rate base and the Commission did not specifically address the topic in those decisions.[45]

Q. Does APS include a similar item associated with its OPEB plan in rate base?

A. Yes. APS includes a regulatory liability associated with its OPEB plan in rate base in the amount of $143.0 million on a Total Company basis and $131.3 million on an ACC jurisdictional basis. A portion of the Total Company balance, $63.4 million, is associated with unrecognized actuarial losses, which is offset by a liability of $206.3 million associated with an unamortized prior service credit.

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[44] See APS response to Data Request AECC 10.1 b., included in Exhibit KCH-15.
[45] See APS responses to Data Requests AECC 13.7, 13.8, and 13.9, included in Exhibit KCH-15.

Q. What is a prior service credit?

A. A prior service credit is created as a result of a plan amendment that retroactively reduces employee benefits. A prior service credit is first netted against any prior service costs, and the remaining net balance it is amortized gradually as a component of net periodic benefit cost.[46]

Q. Is amortization of the prior service credit included in APS's net periodic OPEB cost??

A. Yes. According to the Willis Towers Watson September 2019 Actuarial Valuation Report for Pinnacle West's Postretirement Welfare Plan, OPEB costs were reduced by $37.8 million in 2019 to recognize the amortization of the net prior service credit.[47] Approximately $26.9 million of this amortization was allocated to APS expense, and about $24.7 million of that amount is ACC jurisdictional.[48]

Q. Do you also recommend that the OPEB regulatory liability associated with the unamortized prior service credit and actuarial losses be removed from rate base?

A. Yes. As is the case with the pension actuarial loss, the unamortized OPEB prior service credit and actuarial losses do not represent a cash outlay by APS. Therefore, this balance should not be included as a reduction to rate base.

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[46] ASC 715-60-35-20. Prior service credits are also netted again any transition obligation remaining in accumulated other comprehensive income prior to amortization.

[47] Initial 1.48_APS19RC00268_2019 OPEB Report_CONF, excerpted in Confidential Exhibit KCH-16.

[48] Based on EAB-WP36DR IS – Normalize Employee Benefits Pro Forma, Jan-Dec 2019 tab, approximately 71% of the Non-Service Cost w/o SEBRP PNW and OPEB ROA total is charged to APS expense. According to Schedule C-2, approximately 91.8% of APS's Normalize Employee Benefits adjustment is ACC jurisdictional.

Q. Does APS include other items associated with its pension and OPEB plans in rate base?

A. Yes. APS also includes the balances associated with the funded status of its pension and OPEB plans in rate base. According to GAAP, an employer must recognize the funded status of pension and OPEB plans in its statement of financial position (balance sheet). If a plan is underfunded, an employer must recognize the unfunded projected benefit obligation as a liability, whereas if the plan is overfunded, the employer must recognize an asset in its statement of financial position.

Q. What is the funded status of a pension or OPEB plan?

A. The funded status represents the plan assets at fair value minus the present value of the projected benefit obligation. That is, the funded status represents the economic value of the pension or OPEB plan, including losses that have not yet been recognized in earnings. If a plan is underfunded, that means that the benefits (liabilities) owed to employees and retirees exceed the value of the plan's assets. The inverse is true of an overfunded plan.

Q. What is the funded status of APS's pension and OPEB plans?

A. APS includes a liability of $305.2 million on a Total Company basis and $280.2 million on an ACC jurisdictional basis associated with its underfunded pension plans in rate base. Offsetting this balance is an asset of $52.6 million on a Total Company basis and $48.3 million on an ACC jurisdictional basis associated with the overfunded OPEB plan.[49]

[49] See Schedule B-1, p. 2, lines 8 and 20.

Q. Since GAAP requires that the funded status of pension and OPEB plans be included on the balance sheet for financial reporting purposes, does that mean that a regulated utility must include these balances in rate base earning a return?

A. No. This GAAP requirement is based on FAS No. 158 issued in 2006, which was designed to make financial reporting regarding pension and OPEB plans more understandable to investors. Prior standards relegated information about the overfunded or underfunded status of a plan to the notes to the financial statements, which the FAS Board concluded might lead to inefficient allocation of resources in the capital markets.[50] In other words, this requirement was designed to improve transparency regarding the economic status of plans for financial reporting purposes. It does not necessarily follow that these balances must be included in rate base earning a return.

Q. As you explained, APS includes both the funded status and the unrecognized net actuarial loss associated with its pension plan in rate base. Is there a term for the net balance of these two items?

A. Yes. This is commonly known as a prepaid pension asset. A prepaid pension asset represents the cumulative cash contributions made to the pension plan in excess of the cumulative net periodic pension cost. Conversely, the sum of the overfunded OPEB plan and the unamortized prior service credit and actuarial losses represents an accrued OPEB liability.

Q. Has APS formally proposed to include its prepaid pension asset and accrued OPEB liability in rate base?

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[50] Summary of Statement No. 158. https://www.fasb.org/summary/stsum158.shtml.

A. To my knowledge, APS has never formally requested nor has the Commission has ever explicitly approved inclusion of APS's prepaid pension asset or accrued OPEB liability in rate base. In fact, in response to discovery, the Company claims it does not have a prepaid pension asset/liability or prepaid OPEB asset/liability.[51]

In response to discovery, APS states that the regulatory assets/liabilities related to the funded status of its pension plan have been included in rate base since at least 2005 (Decision No. 67744) as evidenced by Schedule B-1 in that case. Although APS filed no testimony proposing to include regulatory assets or liabilities associated with its pension plan in rate base, the Company contends:

> As part of a rate case, Staff and intervenors review the Company's revenue and expense as set forth in its Standard Filing Requirements through the discovery process and propose adjustments for the Commission's consideration based on their individual reviews. The fact that there is no discussion in these decisions regarding a pension asset or liability shows that this treatment of pension expense is accepted ratemaking practice.[52]

Q. Do you agree that the absence of a discussion of APS's pension assets and liabilities in the historical record is evidence that APS's treatment is accepted ratemaking practice?

A. No. I do not believe that the public interest merit of including these pension-related items in rate base has been fully evaluated by the Commission. The existence and size of a prepaid pension asset can be affected by a number of factors, such as discretionary contributions by the Company and the performance in the market of the Company's pension portfolio. I see no reasonable basis for these factors to be a cause for customers to be required to pay APS a return on

[51] APS responses to Data Request AECC 10.2 a. and 10.9 a., included in Exhibit KCH-15.
[52] See APS's Response to Data Request AECC 13.7, included in Exhibit KCH-15.

any prepaid pension asset. For consistency, I also recommend against including the accrued OPEB liability in rate base.

Q. Are you aware of whether any other jurisdictions allow prepaid pension assets to be included in rate base?

A. Yes. In my experience, some jurisdictions allow prepaid pensions to be included in rate base. On the other hand, at least one jurisdiction, Oregon, devoted an entire docket to considering this question, and determined that prepaid pension assets should <u>not</u> be included in rate base.[53] Other jurisdictions, such as Colorado, limit the allowed return on the prepaid pension asset to the utility's cost of debt, rather than its weighted average cost of capital.[54] The upshot here is that including a prepaid pension asset in rate base should not be considered an automatic or default proposition that occurs without full scrutiny from the Commission. In the case of APS, that full scrutiny does not appear to have occurred. Indeed, APS's own characterization of its pension-related regulatory assets and liabilities is not even couched in terms of a prepaid pension asset. Finally, in the event that a prepaid pension asset is included in rate base, there is an important discussion that must take place regarding the allowed return – a discussion that seems premature at this time since the prepaid pension asset per se has not been placed squarely before the Commission by APS.

Q. Please summarize your recommendation to the Commission regarding pension and OPEB assets and liabilities.

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[53] Oregon Public Utility Commission, Docket No. UM 1633, Order No. 15-226, issued August 3, 2015.
[54] Colorado Public Utilities Commission, Proceeding No.19AL-0268E, *Decision Addressing Applications for Rehearing, Reargument, or Reconsideration; Addressing Related Motions; And Conditionally Requiring a Compliance Tariff Filing* at paragraph 79. Adopted date: May 13, 2020.

A. I recommend that the items presented in Table KCH-4, below, be removed from rate base:

Table KCH-4
Pension and OPEB Items to Remove from Rate Base
Balances as of 6/30/19 ($M)

Description	Total Company	ACC Jurisdictional
Pension Unrecognized Actuarial Loss Asset	$712.9	$654.4
OPEB Prior Service Credit/Unrecognized Loss Liability	($143.0)	($131.3)
Underfunded Pension Liability	($305.2)	($280.2)
Overfunded OPEB Asset	$52.6	$48.3
Net Deferred Tax Liability	($62.5)	($57.4)
Net Rate Base	$254.7	$233.9

My recommended adjustment is presented in Exhibit KCH-7. My adjustment reduces APS's ACC jurisdictional revenue requirement by approximately **$22.141** million relative to APS's filed case.

Pension and OPEB Expense Adjustment

Q. What is the basis for APS's pension and OPEB expense adjustment?

A. APS adjusts its Test Year pension and OPEB expense to reflect the 2019 pension expense of $20.5 million and OPEB expense of -$19.7 million, for a total 2019 pension and OPEB expense of $767 thousand on a Total Company basis. This $767 thousand is included in APS's proposed revenue requirement.[55]

Q. Do you agree that pension and OPEB expense should be based on the 2019 amounts?

A. No. As I have explained in my testimony, APS includes multiple adjustments to its revenue requirement that extend beyond 2019, including plant additions

[55] EAB-WP36DR IS – Normalize Employee Benefits Pro Forma.

through June 30, 2020. I recommend that pension and OPEB expense be based on the average of the 2019 expense and projected 2020 expense, in order to accurately reflect an effective test period ending June 30, 2020.

My calculation utilizes the projected 2020 pension and OPEB expense provided by APS in discovery.[56] Based on the average of 2019 and 2020 expense, estimated APS pension expense is $7.1 million and OPEB expense is -$20.3 million, for a total of -$13.2 million for the year ended June 30, 2020. My recommended adjustment is presented in Exhibit KCH-8. My adjustment reduces APS's ACC jurisdictional revenue requirement by approximately **$12.852** million relative to APS's filed case.

Payroll Expense Adjustment

Q. Please explain your payroll expense adjustment.

A. In APS's payroll expense adjustment, the Company first annualizes its payroll expense to the level incurred in the final quarter of the historical test year ended June 30, 2019.[57] Then, even though APS is nominally using a historical test year ended June 30, 2019, the Company adds a union wage increase projected for April 1, 2020 at its full 12-month value.[58]

I disagree with APS's approach that includes a full year of the union wage increase projected for April 1, 2020 in the revenue requirement. Instead, my adjustment allows APS to recover its projected wage increase on April 1, 2020,

[56] See APS response Data Request AECC 24.1, Attachment ExcelAPS19RC02051, included in Exhibit KCH-15.
[57] See EAB-WP35DR IS – Annualize Payroll Pro Forma.
[58] See APS's response to Data Request AECC 8.7, included in Exhibit KCH-15.

but only for the three months in which it would apply for an effective test period ending June 30, 2020.

My payroll expense adjustment is presented in Exhibit KCH-9. I estimate that it reduces APS's retail revenue requirement by **$1.458** million.

Cash Incentive Adjustment

Q. Please describe APS's cash incentive plan.

A. APS provides an annual incentive award plan for its eligible employees, which determines cash awards based on a combination of Company financial performance, business unit performance, and individual performance. Each business unit performance plan includes a Shareholder Value component.[59]

Q. What has APS proposed with respect to cash incentive compensation?

A. APS is proposing to include 100 percent of the ACC-allocated cash incentive compensation expense in rates, based on the average of cash incentive expense for 2017, 2018 and the Test Year ended June 30, 2019.[60]

Q. In your opinion, is it appropriate to recover the cost of annual cash incentive compensation plans in utility rates?

A. It can be appropriate to recover the cost of annual incentive compensation plans in utility rates to the extent that the compensation in such plans is not excessive and to the extent the goals of such plans are not tied to utility financial performance, but rather to goals such as customer satisfaction, operating efficiency, and safety. While rewarding employees for *financial* performance can be entirely appropriate,

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[59] See APS's response to Data Request AECC 16.2, which is included in Exhibit KCH-15.
[60] See EAB-WP39DR IS-Normalize Cash Incentive.

the responsibility for funding such awards rests most appropriately with shareholders, who are the primary beneficiaries of meeting or exceeding financial targets.

Q. What is your recommendation to the Commission regarding recovery of annual incentive compensation expense?

A. I recommend that shareholders fund the share of APS's cash incentive expense that is related to Company financial performance and Shareholder Value. According to APS's responses to discovery,[61] approximately 39 percent of the total average cash incentive expense for 2017, 2018, and the Test Year was based on Company financial performance, and an additional 15 percent of the average total cash incentive expense was based on Shareholder Value from the business unit performance component. My recommended adjustment is presented in Exhibit KCH-10. My adjustment reduces APS's ACC jurisdictional revenue requirement by approximately **$20.362** million relative to APS's filed case.

Customer Annualization Adjustment

Q. Please describe APS's customer annualization adjustment.

A. As described by Mr. Snook, APS's customer annualization adjustment reflects the change in the number of customers by rate class as of June 2019 compared to the average customer level experienced during the preceding year.[62] Customer counts increased for some classes and declined for others, but the net impact of APS's adjustment is an increase in Test Year revenues.

[61] APS's responses to Data Requests AECC 6.1 (Supplemental), 16.1 and 16.2, included in Exhibit KCH-15.
[62] Direct Testimony of Leland R. Snook, p. 17-18.

Q. Please describe your recommended customer annualization adjustment.

A. My adjustment reflects the change in the number of customers by rate class as of December 31, 2019 compared to the June 2019 customer levels used in APS's adjustment. I used the same calculation approach used by APS but advanced the customer count measurement date by six months. This measurement date is appropriate because December 31, 2019 is the midpoint of the effective test period ending June 30, 2020. This midpoint measurement date can serve as a proxy for the average customer levels experienced during the effective test period ending June 30, 2020. This adjustment is entirely appropriate in light of the 12 months of post-test-year plant that APS is proposing to add to rate base. It is not reasonable for customers to be asked to pay for plant added in 2020 using a 2019 customer count.

Like APS's adjustment, customer counts increased for some classes and declined for others. Overall, my adjustment reduces the ACC jurisdictional revenue deficiency by approximately **$2.261** million relative to APS's filed case. My recommended adjustment is presented in Exhibit KCH-11.

Return on Equity

Q. What return on equity is APS proposing?

A. APS is proposing an ROE of 10.15%,[63] which is 15 basis points over the 10.00% ROE included in the Settlement Agreement approved in Decision No. 76295 in Docket Nos. E-01345A-16-0036 and E-01345A-16-0123.

Q. Does AECC support APS's request?

[63] *See* Direct Testimony of Ann E. Bulkley, p. 3.

A. No. Please refer to Exhibit KCH-12, which shows the ROEs for vertically integrated electric utilities approved in the United States from July 1, 2019 through June 30, 2020, as reported by Regulatory Research Associates, a group within S&P Global Market Intelligence. The median ROE for this group was 9.75%. APS's proposed ROE of 10.15% is 40 basis points above the national median ROE.

Q. If APS's allowed ROE were to be set at the national median of approximately 9.75%, how would APS's effective return be impacted by the fair value increment?

A. Unlike the vast majority of utilities in the country, Arizona utilities are allowed an incremental return on the difference between original cost rate base and fair value rate base, known as the "fair value increment." The fair value increment provides Arizona utilities with a premium return above the nominal ROE applied to original cost rate base.[64] Thus, even if APS's nominal ROE were to remain in line with the national median, APS's effective ROE would actually be somewhat higher, due to the fair value increment.

Q. In offering this discussion of national trends, are you intending to supplant the Commission's consideration of traditional cost-of-capital analysis?

A. No. I fully expect that Staff, and likely RUCO, will file cost-of-capital analyses for the Commission's consideration, along with that filed by APS. My discussion of national trends is intended to supplement that analysis.

[64] APS proposes a return on the fair value increment of 1.0% in this case. See the Direct Testimony of Ann E. Bulkley, p. 73.

Q. What would be the revenue requirement impact if APS's ROE were set at 9.75%?

A. The revenue requirement impact of setting APS's allowed ROE equal to 9.75% reduces APS's ACC jurisdictional revenue requirement by approximately **$23.855** million relative to APS's filed case. This impact is included in my presentation of AECC's recommended revenue requirement in Exhibit KCH-1. I have incorporated an ROE of 9.75% into AECC's overall revenue requirement recommendations at this time, pending further information being presented into the record by other parties.

Navajo Power Plant Costs Regulatory Asset Return Adjustment

Q. What ratemaking treatment is APS proposing for the Navajo Generating Station ("Navajo")?

A. APS is a 14% co-owner of Navajo Units 1, 2 and 3, which totaled 315 MW. All three of these units retired in late 2019. However, APS's depreciation rates for Navajo were designed to recover APS's capital investment through 2026.[65] This means that APS still has a sizable undepreciated balance on its books although Navajo has retired. APS transferred the undepreciated plant balance into a regulatory asset and proposes to amortize that balance through 2026. As of June 30, 2019, the Navajo unrecovered plant regulatory asset totaled $82.8 million. This rate base balance is offset by a deferred tax liability of $20.5 million.[66]

Q. What is your assessment of APS's proposal?

[65] See Docket No. E-01345A-16-0036, Direct Testimony of Dr. Ronald E. White, Attachment REW–2DR (2016 Depreciation Rate Study), Statement H, page 81.
[66] See EAB-WP5DR Schedule B-1, Reg Asset Liab tab, line 3.

A. Generally, I do not object to APS's proposed approach, except I do not believe it is reasonable for customers to pay an equity-level return on utility investment that is no longer used and useful. Therefore, I recommend that the rate of return on the Navajo regulatory asset be set at APS's cost of long-term debt.

Q. Please explain the reasoning behind your recommendation.

A. At a fundamental level, there must be a reasonable nexus between the costs customers pay and the used and usefulness of the facilities for which customers are charged. APS and the other co-owners of the Navajo units determined that it was no longer cost effective to operate this plant. In a competitive market, the owners' remaining investment in this plant would simply be written off, *i.e.*, charged to shareholders. While this is indeed an option under monopoly regulation, it is also important that the monopoly provider not be disincentivized to take action to shut down uneconomic facilities. But the full burden of plant obsolescence should not fall entirely on customers. A reasonable balance must be struck. I believe my recommendation strikes that balance by allowing the Company to recover the remainder of its Navajo investment through 2026 (*i.e.*, return <u>of</u> capital) while earning a scaled-down return on the unamortized balance. At the same time, customers, who will be paying a full return on the plant necessary to <u>replace</u> the Navajo units, would be protected from simultaneously paying a full rate of return on both the replacement plant and the uneconomic plant that was no longer used and useful.

Q. What is the revenue requirement impact of your recommended Navajo return adjustment?

A. My recommended adjustment is presented in Exhibit KCH-13. This adjustment reduces the ACC jurisdictional revenue deficiency by approximately **$2.560** million. This impact is calculated relative to the weighted average cost of capital incorporating the median ROE of 9.75%, as discussed above. The impact of this adjustment will vary depending on the weighted average cost of capital approved in this case.

Transfer of DSM Expense to DSMAC Adjustment Charge

Q. Please explain your recommendation to transfer DSM expenses to the DSMAC.

A. I recommend that the $20 million of DSM expenses currently recovered in base rates be transferred to the DSMAC. While this will reduce base rates by approximately $20 million, it will not impact the net revenue increase because it is revenue neutral on an overall basis. I will discuss this adjustment in greater detail in my rate design testimony, but I am mentioning it here due to its impact on the base revenue requirement.

Q. What is the base revenue requirement impact of your recommended adjustment?

A. My recommended adjustment is presented in Exhibit KCH-14. This adjustment reduces the ACC jurisdictional revenue deficiency by approximately **$20.000** million.

IV. ANCILLARY IMPACTS OF AECC COST ALLOCATION RECOMMENDATIONS

Q. Please explain your cost allocation recommendations that impact the jurisdictional revenue requirement.

A. As I will discuss primarily in my forthcoming rate design testimony, I propose that the AG-X class be excluded from the allocation of certain production costs. Removing the AG-X load from those allocation factors slightly reduces the ACC jurisdictional share of certain production costs. This does not impact the Total Company revenue requirement and is not included in Tables KCH-1 or KCH-2.

V. POWER SUPPLY ADJUSTMENT ("PSA") AG-X PROVISION

Q. Please describe the AG-X provision in the PSA Plan of Administration ("POA") that was adopted in the last rate case.

A. In Docket Nos. E-01345A-16-0036 and E-01345A-16-0123, APS proposed that the predecessor to the AG-X program, AG-1, be discontinued, and initially designed its proposed rates to reflect that recommendation. However, as part of the Settlement Agreement in that case, AG-1 was replaced with AG-X. Since AG-X customers are subject to a reserve capacity charge that is less than the full standard generation charges, a provision was adopted in the PSA POA to mitigate the impact of this lower AG-X revenue requirement relative to APS's filed case in that proceeding.[67] This provision excludes $1.25 million per month, or $15 million per year, of off-system sales margins from the PSA.

[67] Docket Nos. E-01345A-16-0036 and E-01345A-16-0123, Settlement Agreement (March 24, 2017), at ¶ 23.6. Approved in Decision No. 76295 (August 18, 2017).

In the current case, however, APS designed its proposed rates to collect its full proposed base revenue requirement from its rate schedules, including AG-X. As such, based on APS's as-filed case, the PSA mitigation provision would no longer be necessary to accommodate the lower AG-X revenue requirement as of the rate effective date of this case. However, APS did not propose to eliminate the mitigation provision from the PSA POA, but responded in discovery that "[t]his pro forma adjustment was mistakenly left out of the calculation of the revenue requirement."[68] In other words, APS proposes to continue the PSA mitigation mechanism and reduce its proposed base rates by $15 million in light of that continuation.[69]

As I will discuss in my rate design testimony, I propose that the PSA mechanism be retained for the purpose of accommodating a redesigned AG-Y program. However, it is no longer needed to accommodate AG-X, as demonstrated in the Company's direct filing in this case. If the Commission does not adopt a redesigned AG-Y program, but instead adopts an AG-Y program that more closely resembles that proposed by APS, then I recommend that the PSA mitigation mechanism be eliminated.

VI. APS PROPOSED PROPERTY TAX DEFERRAL

Q. Is APS proposing to receive authorization for a property tax deferral?

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[68] APS response to Data Request AECC 23.2, included in Exhibit KCH-15.

[69] APS provided a corrected version of its cost-of-service study in its Sixth Supplemental Response to Data Request Staff 5.7, Staff 5.7_ExcelAPS19RC02085_Updated COSS. The narrative response is included in Exhibit KCH-15.

A. Yes. According to the Direct Testimony of Ms. Elizabeth A. Blankenship, APS is concerned that its property tax rate and related property tax expense could increase significantly. APS proposes to defer for future recovery 100% of all changes to Arizona property tax expense above or below the Adjusted Test Year level of $177 million caused by changes to the applicable Arizona composite property tax rate (not changes in the assessed value of property). APS will track and record the deferral in the same manner as it currently does and will propose in the next rate case to recover any positive balance from customers over ten years and to refund any negative balance over three years.[70]

Q. Do you agree that the property tax deferral should be continued?

A. No. I recommend the property tax deferral be discontinued going forward.

Q. Why should the property tax deferral be discontinued?

A. This deferral mechanism is an example of single-issue ratemaking. Single-issue ratemaking occurs when utility rates are adjusted, or costs are deferred, in response to a change in a single cost item considered in isolation. It ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

Setting rates based on a single cost item runs contrary to the basic principles of traditional utility regulation. When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, the standard practice is to review and consider all relevant factors, rather than just a single factor. To consider some costs in isolation might cause a

[70] Direct Testimony of Elizabeth A. Blankenship, pp. 41-42.

commission to allow a utility to increase rates (or defer costs) to recover higher expenses in one area without recognizing counterbalancing savings in another area, or vice versa. For these reasons, single-issue ratemaking, absent a compelling public interest, is generally not sound regulatory practice.

Ratemaking is not intended to be a simple exercise in expense reimbursement. Rates are set with the expectation that utility management will run the business as efficiently as possible, while providing safe and reliable service to customers and meeting its other regulatory responsibilities. In so doing, the Company is given the opportunity to achieve or exceed its authorized return to its shareholders. As part of this arrangement, utility management should be expected to cope with normal business risks and the operation of economic forces. Deferral mechanisms insulate the utility from these normal business risks.

The current property tax deferral mechanism was implemented as part of a comprehensive settlement agreement in APS's 2011 rate case,[71] and permitted to continue as part of the settlement agreement in the last rate case.[72] Those settlement agreements were the products of multi-party negotiations that considered the tradeoffs among a multitude of issues. In my opinion, the property tax deferral does not warrant adoption on its own merit. It is appropriate for it to be eliminated at this time.

VII. FORMULA RATE

Q. Has APS proposed a formula rate in this proceeding?

[71] Docket No. E-01345A-11-0224, Decision No. 73183.
[72] Docket Nos. E-01345A-16-0036 and E-01345A-16-0123, Decision No. 76295.

A. No. However, Mr. Snook introduces a "formula prototype," arguing that a formula rate would allow for annual scrutiny of APS's earnings, elimination of certain adjustor mechanisms and improved rate gradualism.[73]

Q. What is your recommendation to the Commission regarding APS's formula rate suggestion?

A. I recommend that the formula rate prototype be rejected by the Commission. APS's formula rate concept, in which annual rate adjustments would be implemented based on updating formula inputs, would not allow for the same level of scrutiny as is possible in a general rate case proceeding. The burden of proof for increasing rates to customers served by a regulated monopoly properly rests with the monopoly. The requirement to provide convincing evidence to justify a change in rates should not be supplanted by a formula, as such a change would not serve the public interest. As the evidence provided in this case will demonstrate, evaluating the revenue, expense, and rate base components of the revenue requirement is a complex exercise. I believe that this exercise is best undertaken in the context of a general rate case. Moreover, ratemaking extends beyond the question of addressing the utility's request for revenue, but also involves the important matters of cost allocation and rate design, topics likely to get short shrift under a formula rate scheme.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[73] Direct Testimony of Leland R. Snook, pp. 22-24.

EXHIBIT KCH-1

Comparison of APS and AECC
Computation of Increase in Gross Revenue Requirements
For the Adjusted Test Year Ending June 30, 2019
(Thousands of Dollars)

	(a)	(b)	(c)	(d)
		ACC Jurisdiction		
Line No.	Description	APS Original Cost[1]	AECC Adjustments	AECC Original Cost
1	Adjusted Rate Base - Original Cost	$ 8,872,984	$ (343,489)	$ 8,529,495
2	Adjusted Operating Income	640,218	61,928	702,146
3	Current Rate of Return	7.22%	1.01%	8.23%
4	Required Operating Income	657,488	(44,217)	613,271
5	Requested Rate of Return	7.41%	-0.22%	7.19%
6	Adjusted Operating Income Deficiency	17,270	(106,145)	(88,875)
7	Gross Revenue Conversion Factor	1.3288		1.3288
8	Adjusted Increase in Base Revenue Requirement	$ 22,948	$ (141,046)	$ (118,098)
Line No.	Description	APS FV Cost[1]	AECC Adjustments	AECC FV Cost
9	Adjusted Rate Base - RCND	$ 15,747,542	$ (340,072)	$ 15,407,471
10	Adjusted Rate Base - Fair Value (FV)	12,310,263	(341,780)	11,968,483
11	Fair Value Rate Base Increment	3,437,279	1,709	3,438,988
12	Requested Rate of Return with 1% FV Increment	5.62%	-0.21%	5.41%
13	Required Operating Income	691,837	(44,342)	647,495
14	Incremental Fair Value Required Operating Income	34,349	(125)	34,224
15	Gross Revenue Conversion Factor	1.3288		1.3288
16	Fair Value Increment	45,643	(166)	45,477
17	Requested Increase in Base Revenue Requirement	68,591	(141,212)	(72,621)
18	Rider Revenue Transferred to Base Rates	115,042	20,000	135,042
19	Net Requested Increase in Revenue Requirement	$ 183,633	$ (121,212)	$ 62,421
20	Total Present Sales Revenue to Ultimate Retail Customers	$ 3,279,191	$ 2,438	$ 3,281,629
21	Adjusted Percentage Increase	5.60%	-3.70%	1.90%

Data Sources:
1. APS Schedule A-1 & H-1.

SUMMARY OF AECC "PLACEHOLDER" COST OF CAPITAL
TEST YEAR ENDED 6/30/2019
(Dollars in Thousands)

		Adjusted End of Test Year 6/30/2019			
Line No.	Invested Capital	Amount	%	Cost Rate	Composite Cost
1	Long-Term Debt	$ 4,726,125	45.33%	4.10%	1.86%
2	Preferred Stock	$ 0	0.00%	0.00%	0.00%
3	Common Equity	$ 5,700,968	54.67%	9.75%	5.33%
4	Short-Term Debt	$ 0	0.00%	0.00%	0.00%
5	Total	$ 10,427,093	100.00%		7.19%

SUMMARY OF APS PROPOSED COST OF CAPITAL[1]
TEST YEAR ENDED 6/30/2019
(Dollars in Thousands)

		Adjusted End of Test Year 6/30/2019			
Line No.	Invested Capital	Amount	%	Cost Rate	Composite Cost
6	Long-Term Debt	$ 4,726,125	45.33%	4.10%	1.86%
7	Preferred Stock	$ 0	0.00%	0.00%	0.00%
8	Common Equity	$ 5,700,968	54.67%	10.15%	5.55%
9	Short-Term Debt	$ 0	0.00%	0.00%	0.00%
10	Total	$ 10,427,093	100.00%		7.41%

Data Source:
1. APS Standard Filing Requirements, Exhibit D-1, p. 1 of 2.

SUMMARY OF AECC "PLACEHOLDER" COST OF CAPITAL WITH 1% FV INCREMENT
TEST YEAR ENDED 6/30/2019
(Dollars in Thousands)

		Adjusted End of Test Year 6/30/2019				
Line No.	Invested Capital		Amount	%	Cost Rate	Composite Cost
1	Long-Term Debt	$	3,866,420	32.31%	4.10%	1.32%
2	Preferred Stock	$	0	0.00%	0.00%	0.00%
3	Common Equity	$	4,663,075	38.96%	9.75%	3.80%
4	Short-Term Debt	$	0	0.00%	0.00%	0.00%
5	Fair Value Rate Base Increment	$	3,438,988	28.73%	1.00%	0.29%
6	Total	$	11,968,483	100.00%		5.41%

SUMMARY OF APS PROPOSED COST OF CAPITAL WITH 1% FV INCREMENT[1]
TEST YEAR ENDED 6/30/2019
(Dollars in Thousands)

		Adjusted End of Test Year 6/30/2019				
Line No.	Invested Capital		Amount	%	Cost Rate	Composite Cost
7	Long-Term Debt	$	4,022,124	32.67%	4.10%	1.34%
8	Preferred Stock	$	0	0.00%	0.00%	0.00%
9	Common Equity	$	4,850,860	39.41%	10.15%	4.00%
10	Short-Term Debt	$	0	0.00%	0.00%	0.00%
11	Fair Value Rate Base Increment	$	3,437,279	27.92%	1.00%	0.28%
12	Total	$	12,310,263	100.00%		5.62%

Data Source:

1. Leland R. Snook Attachment LRS-2DR Calculation of Fair Value Increment.

AECC Original Cost Rate Base
For the Adjusted Test Year Ending June 30, 2019
(Thousands of Dollars)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		APS Application[1] Adjusted Test Year Ended 6/30/2019		AECC PTYP Avg. Rate Base Adjustment		AECC Existing Plant Avg. Rate Base Adjustment		AECC West Phx 4 Rate Base Adjustment	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
1	Gross Utility Plant in Service	$ 21,428,208	$ 18,264,729	$ (380,650)	$ (379,090)	$ 0	$ 0	$ 0	$ 0
2	Less: Accumulated Depreciation and Amortization	7,818,974	6,863,807	7,550	7,517	(273,746)	(272,418)	(164)	(163)
3	Net Utility Plant in Service	13,609,234	11,400,922	(388,199)	(386,607)	273,746	272,418	164	163
4	Less: Total Deductions	5,741,462	5,636,420	(6,745)	(6,729)	(3,954)	(3,945)	(47)	(47)
5	Plus: Total Additions	3,252,086	3,108,482	0	0	0	0	0	0
6	Total Rate Base	$ 11,119,858	$ 8,872,984	$ (381,454)	$ (379,878)	$ 277,700	$ 276,363	$ 211	$ 210

Data Source:
1. APS SFR Schedule B-1, p. 1 of 2.

AECC RCND Rate Base
For the Adjusted Test Year Ending June 30, 2019
(Thousands of Dollars)

		APS Application[1] Adjusted Test Year Ended 6/30/2019		AECC PTYP Avg. Rate Base Adjustment		AECC Existing Plant Avg. Rate Base Adjustment		AECC West Phx 4 Rate Base Adjustment	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
7	Gross Utility Plant in Service	$ 40,391,451	$ 34,340,989	$ (380,650)	$ (379,090)	$ 0	$ 0	$ 0	$ 0
8	Less: Accumulated Depreciation and Amortization	15,220,925	13,304,371	7,550	7,517	(276,513)	(274,349)	(164)	(163)
9	Net Utility Plant in Service	25,170,526	21,036,618	(388,199)	(386,607)	276,513	274,349	164	163
10	Less: Total Deductions	8,517,616	8,397,558	(6,745)	(6,729)	(5,457)	(5,431)	(47)	(47)
11	Plus: Total Additions	3,252,086	3,108,482	0	0	0	0	0	0
12	Total Rate Base	$ 19,904,996	$ 15,747,542	$ (381,454)	$ (379,878)	$ 281,969	$ 279,780	$ 211	$ 210

Data Source:
1. APS SFR Schedule B-1, p. 2 of 2.

AECC Original Cost Rate Base
For the Adjusted Test Year Ending June 30, 2019
(Thousands of Dollars)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		AECC Recent Deferrals Adjustment		AECC Pension & OPEB RB Adjustment		AECC Adjusted Test Year Ended 6/30/2019	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
1	Gross Utility Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 21,047,559	$ 17,885,639
2	Less: Accumulated Depreciation and Amortization	0	0	0	0	$ 7,552,614	$ 6,598,742
3	Net Utility Plant in Service	0	0	0	0	13,494,945	11,286,896
4	Less: Total Deductions	(2,093)	(2,083)	(510,776)	(468,888)	$ 5,217,846	$ 5,154,730
5	Plus: Total Additions	(8,457)	(8,415)	(765,519)	(702,739)	$ 2,478,109	$ 2,397,328
6	Total Rate Base	$ (6,364)	$ (6,332)	$ (254,743)	$ (233,852)	$ 10,755,208	$ 8,529,495

AECC RCND Rate Base
For the Adjusted Test Year Ending June 30, 2019
(Thousands of Dollars)

		AECC Recent Deferrals Adjustment		AECC Pension & OPEB RB Adjustment		AECC Adjusted Test Year Ended 6/30/2019	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
1	Gross Utility Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 40,010,802	$ 33,961,899
2	Less: Accumulated Depreciation and Amortization	0	0	0	0	$ 14,951,798	$ 13,037,376
3	Net Utility Plant in Service	0	0	0	0	25,059,004	20,924,524
4	Less: Total Deductions	(2,093)	(2,083)	(510,776)	(468,888)	$ 7,992,498	$ 7,914,381
5	Plus: Total Additions	(8,457)	(8,415)	(765,519)	(702,739)	$ 2,478,109	$ 2,397,328
6	Total Rate Base	$ (6,364)	$ (6,332)	$ (254,743)	$ (233,852)	$ 19,544,615	$ 15,407,471

AECC Income Statement
For the Adjusted Test Year Ending June 30, 2019
(Thousands of Dollars)

Line No.	(a) Description	(b) APS Application[1] Adjusted Test Year Ended 6/30/2019 Total Company	(c) ACC Jurisdiction	(d) AECC Post Test Period Depreciation Exp. Adjustment Total Company	(e) ACC Jurisdiction	(f) Pension & OPEB Expense Adjustment Total Company	(g) ACC Jurisdiction	(h) Pro Forma Test Year Payroll Expense Adjustment Total Company	(i) ACC Jurisdiction
	Electric Operating Revenues								
1	Revenues from Base Rates	$ 3,289,998	$ 3,279,191	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2	Revenues from Surcharges	0	0	0	0	0	0	0	0
3	Other Electric Revenues	210,831	142,230	0	0	0	0	0	0
4	Total	3,500,829	3,421,422	0	0	0	0	0	0
	Operating Expenses:								
5	Electric Fuel and Purchased Power	955,136	943,995	0	0	0	0	0	0
6	Operations and Maintenance Excluding Fuel Expense	738,809	884,542	0	0	0	0	(1,588)	(1,458)
7	Depreciation and Amortization	722,843	647,485	(18,023)	(17,300)	(14,001)	(12,852)	0	0
8	Income Taxes	123,312	113,662	5,859	5,642	3,464	3,180	393	361
9	Other Taxes	230,467	191,519	(5,653)	(5,499)	0	0	0	0
10	Total	2,770,567	2,781,204	(17,817)	(17,157)	(10,536)	(9,672)	(1,195)	(1,097)
11	Operating Income	730,262	640,218	17,817	17,157	10,536	9,672	1,195	1,097
	Other Income (Deductions)								
12	Income Taxes	6,467	0	0	0	0	0	0	0
13	Allowance for Funds Used During Construction	43,927	0	0	0	0	0	0	0
14	Other Income (Deductions)	34,998	0	0	0	0	0	0	0
15	Other Expenses	(22,582)	0	0	0	0	0	0	0
16	Total	62,810	0	0	0	0	0	0	0
17	Income Before Interest Deductions	793,072	640,218	17,817	17,157	10,536	9,672	1,195	1,097
	Interest Deductions:								
18	Interest on Long -Term Debt	227,758	0	0	0	0	0	0	0
19	Allowance for Borrowed Funds Used During Construction	(23,293)	0	0	0	0	0	0	0
20	Total	204,465	0	0	0	0	0	0	0
21	Net Income	$ 588,607	$ 640,218	$ 17,817	$ 17,157	$ 10,536	$ 9,672	$ 1,195	$ 1,097

Data Source:
1. APS SFR Schedule C-1.

AECC Income Statement
For the Adjusted Test Year Ending June 30, 2019
(Thousands of Dollars)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		AECC Cash Incentive Expense Adjustment		AECC Customer Annualization Adjustment		AECC Navajo Reg. Asset Return Adjustment	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
	Electric Operating Revenues						
1	Revenues from Base Rates	$ 0	$ 0	$ 2,438	$ 2,438	$ 0	$ 0
2	Revenues from Surcharges	0	0	0	0	0	0
3	Other Electric Revenues	0	0	0	0	0	0
4	Total	0	0	2,438	2,438	0	0
	Operating Expenses:						
5	Electric Fuel and Purchased Power	0	0	178	178	0	0
6	Operations and Maintenance Excluding Fuel Expense	(22,182)	(20,363)	0	0	(2,559)	(2,559)
7	Depreciation and Amortization	0	0	0	0	0	0
8	Income Taxes	5,489	5,039	559	559	633	633
9	Other Taxes	0	0	0	0	0	0
10	Total	(16,693)	(15,324)	737	737	(1,926)	(1,926)
11	Operating Income	16,693	15,324	1,701	1,701	1,926	1,926
	Other Income (Deductions)						
12	Income Taxes	0	0	0	0	0	0
13	Allowance for Funds Used During Construction	0	0	0	0	0	0
14	Other Income (Deductions)	0	0	0	0	0	0
15	Other Expenses	0	0	0	0	0	0
16	Total	0	0	0	0	0	0
17	Income Before Interest Deductions	16,693	15,324	1,701	1,701	1,926	1,926
	Interest Deductions:						
18	Interest on Long -Term Debt	0	0	0	0	0	0
19	Allowance for Borrowed Funds Used During Construction	0	0	0	0	0	0
20	Total	0	0	0	0	0	0
21	Net Income	$ 16,693	$ 15,324	$ 1,701	$ 1,701	$ 1,926	$ 1,926

AECC Income Statement
For the Adjusted Test Year Ending June 30, 2019
(Thousands of Dollars)

	(a)	(b)	(c)	(d)	(e)
		AECC Transfer DSM Exp. to DSMAC Adjustment		AECC Proforma	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
	Electric Operating Revenues				
1	Revenues from Base Rates	$ 0	$ 0	$ 3,292,436	$ 3,281,629
2	Revenues from Surcharges	0	0	$ 0	$ 0
3	Other Electric Revenues	0	0	$ 210,831	$ 142,230
4	Total	0	0	3,503,267	3,423,860
	Operating Expenses:				
5	Electric Fuel and Purchased Power	0	0	$ 955,314	$ 944,173
6	Operations and Maintenance Excluding Fuel Expense	(20,000)	(20,000)	$ 692,480	$ 840,162
7	Depreciation and Amortization	0	0	$ 690,819	$ 617,333
8	Income Taxes	4,949	4,949	$ 144,658	$ 134,025
9	Other Taxes	0	0	$ 224,814	$ 186,021
10	Total	(15,051)	(15,051)	2,708,086	2,721,713
11	Operating Income	15,051	15,051	795,181	702,146
	Other Income (Deductions)				
12	Income Taxes	0	0	$ 6,467	$ 0
13	Allowance for Funds Used During Construction	0	0	$ 43,927	$ 0
14	Other Income (Deductions)	0	0	$ 34,998	$ 0
15	Other Expenses	0	0	$ (22,582)	$ 0
16	Total	0	0	62,810	0
17	Income Before Interest Deductions	15,051	15,051	857,991	702,146
	Interest Deductions:				
18	Interest on Long -Term Debt	0	0	$ 227,758	$ 0
19	Allowance for Borrowed Funds Used During Construction	0	0	$ (23,293)	$ 0
20	Total	0	0	204,465	0
21	Net Income	$ 15,051	$ 15,051	$ 653,526	$ 702,146

EXHIBIT KCH-2

AECC Post-Test Year Plant Rate Base Adjustment

Rate Base Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Post-Test Year Plant Rate Base**
AECC Adjustment Reflects Average Post-Test Year Plant Rate Base Amount.

Line No.	Description (a)	AECC Total Company Amount (b)	ACC Jurisdictional Allocation Factor (c)	AECC ACC Jurisdictional Amount (d)	Source (e)
1	Gross Utility Plant in Service	$ (380,650)	Various	$ (379,090)	See Page 2, Ln. 16, Col. (d).
2	Less: Accumulated Depreciation & Amort.	7,550	Various	7,517	See Page 2, Ln. 32, Col. (d).
3	Net Utility Plant in Service	(388,199)		(386,607)	= Ln. 1 - Ln. 2
4	Less: Total Deductions	(6,745)	99.76%	(6,729)	See Page 2, Ln. 37, Col. (b).
5	Total Additions	0		0	
6	Total Rate Base	$ (381,454)		$ (379,878)	= Ln. 3 - Ln. 4 + Ln. 5
	Original Cost Impact				
7	APS Requested Rate of Return			7.41%	
8	Required Operating Income			(28,149)	= Ln. 6 x Ln. 7
9	Gross Revenue Conversion Factor			1.3288	
10	Estimated Revenue Requirement Impact			$ (37,404)	= Ln. 8 x Ln. 9
	Fair Value Impact				
11	Fair Value Return Before Adjustment			5.62%	
12	Fair Value Return After Adjustment			5.56%	
13	Change in Fair Value Return			-0.06%	
14	Fair Value Rate Base Before Adjustment			$ 12,310,263	
15	Fair Value Rate Base After Adjustment			$ 11,930,385	
16	Change in Fair Value Rate Base			$ (379,878)	=Ln. 6
17	Fair Value Required Operating Income Impact from FV Return Change			$ (7,387)	= Ln. 14 x Ln. 13
18	Fair Value Required Operating Income Impact from FV Rate Base Change			$ (21,121)	= Ln. 16 x Ln. 12
19	Total Fair Value Required Operating Income Impact			$ (28,508)	= Ln. 17 + Ln. 18
20	Incremental Fair Value Operating Income Impact			(359)	= Ln. 19 - ln. 8
21	Gross Revenue Conversion Factor			1.3288	
22	Estimated Fair Value Revenue Requirement Impact			(477)	= Ln. 20 x Ln. 21
23	Total Revenue Requirement Impact			(37,881)	= Ln. 10 + Ln. 22

AECC Recommended Rate Base Adjustments
to Reflect Average Net Plant in Service
($000s)

AECC Post-Test Year Plant Gross Plant in Service Adjustment[1]

Line No.	Month (a)	Total Company (OCRB) Production (b)	Distribution/ Gen'l & Int. (c)	Total (d)
1	Jun-19	29,510	2,060	31,570
2	Jul-19	37,705	33,227	70,933
3	Aug-19	52,437	91,579	144,016
4	Sep-19	60,973	120,772	181,745
5	Oct-19	87,058	150,525	237,583
6	Nov-19	127,263	182,745	310,008
7	Dec-19	154,203	272,360	426,562
8	Jan-20	165,434	296,117	461,551
9	Feb-20	179,198	327,108	506,307
10	Mar-20	194,115	381,681	575,795
11	Apr-20	255,112	415,560	670,672
12	May-20	267,604	446,044	713,647
13	Jun-20	277,354	495,882	773,236
14	13-Mo. Avg.	145,228	247,358	392,587
15	APS Proposed Amount	277,354	495,882	773,236
16	**AECC Adjustment**	**(132,126)**	**(248,523)**	**(380,650)**

AECC Post-Test Year Plant Accumulated Depreciation & Amortization Adjustment[2]

Line No.	Month (a)	Total Company (OCRB) Production (b)	Distribution/ Gen'l & Int. (c)	Total (d)
17	Jun-19	0	0	0
18	Jul-19	141	162	303
19	Aug-19	312	610	922
20	Sep-19	508	1,201	1,709
21	Oct-19	773	1,937	2,710
22	Nov-19	1,131	2,830	3,961
23	Dec-19	1,527	4,162	5,689
24	Jan-20	1,955	5,610	7,565
25	Feb-20	2,425	7,210	9,635
26	Mar-20	2,944	9,076	12,020
27	Apr-20	3,698	11,108	14,806
28	May-20	4,496	13,289	17,785
29	Jun-20	5,326	15,714	21,040
30	13-Mo. Avg.	1,941	5,608	7,550
31	APS Proposed Amount	0	0	0
32	**AECC Adjustment**	**1,941**	**5,608**	**7,550**

AECC Post-Test Year Plant Accumulated Deferred Income Tax Adjustment[2]

Line No.	Month (a)	Total Company (OCRB) Production (b)
33	Balance as of Jun. 2019	0
34	Balance as of Jun. 2020	13,491
35	Beg./End. Avg.	6,745
36	APS Proposed Amount	13,491
37	**AECC Adjustment**	**(6,745)**

Data Sources:

1. Barbara Lockwood's PTYP workpapers by Function & Elizabeth Blankenship's PTYP Additions Pro Forma workpapers.
2. Elizabeth Blankenship's PTYP Additions Pro Forma Rate Base workpaper.

EXHIBIT KCH-3

AECC Post-Test Year Plant Additions Depreciation & Property Tax Expense Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Post-Test Year Plant Additions Depreciation & Property Tax Expense**
AECC Adjustment to Post-Test Year Plant Additions Depreciation and Property Tax Expense Based on Average Rate Base.

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$ 0		$ 0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense				
9	Depreciation and Amortization	$ (18,023)	Various	$ (17,300)	See Page 2, Ln. 9, Col. (d); Col. (i)
10	Other Taxes	(5,653)	Various	(5,499)	See Page 2, Ln. 18, Col. (d); Col. (i)
11	**Total excluding Income Taxes**	$ (23,676)		$ (22,799)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 23,676		$ 22,799	= Ln. 5 - Ln. 11
13	Income Taxes	5,859		5,642	= 24.745% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 17,817**		**$ 17,157**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	**$0**		**$0**	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 17,817		$ 17,157	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	**$0**		**$0**	= Sum (Lns. 23:26)
28	Net Income	$ 17,817		$ 17,157	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.3288	
30	Estimated Revenue Requirement Impact			**$ (22,799)**	= Ln. 28 x Ln. 29

AECC Recommended Post-Test Year Plant Expense Adjustments
to Reflect Average Net Plant in Service
($000s)

AECC Post-Test Year Plant Depreciation Expense Adjustment[1]

Line No.	Description	Total Company: Production	Total Company: Distribution/ Gen'l & Int.	Total Company: Total	ACC Jurisdictional Amount Calculation: Production		Distribution/ Gen'l & Int.		Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Fossil	4,330			4,309	99.52%			
2	Nuclear	454			452	99.53%			
3	Other (Renewable)	543			543	100.00%			
4	AECC Pro Forma Depreciation Expense	5,326	15,714	21,040	5,304		14,889	94.75%	20,193
					ACC Jurisdictional APS Adjustment[2]				
5	Fossil	8,337			8,297	99.52%			
6	Nuclear	704			701	99.53%			
7	Other (Renewable)	926			926	100.00%			
8	APS Proposed Annualized Amount	9,966	29,097	39,064	9,923		27,570	94.75%	37,493
9	**AECC Adjustment**	**(4,640)**	**(13,383)**	**(18,023)**	**(4,620)**		**(12,681)**		**(17,300)**

AECC Post-Test Year Plant Property Tax Expense Adjustment[1]

Line No.	Description	Total Company: Production	Total Company: Distribution/ Gen'l & Int.	Total Company: Total	ACC Jurisdictional Amount Calculation: Production		Distribution/ Gen'l & Int.		Total
10	Fossil	633			630	99.49%			
11	Nuclear	259			258	99.43%			
12	Other (Renewable)	51			51	100.00%			
13	AECC Pro Forma PTYP Property Tax Expense	943	4,772	5,715	939		4,623	96.88%	5,562
					ACC Jurisdictional APS Adjustment[2]				
14	Fossil	1,209			1,203	99.49%			
15	Nuclear	495			493	99.43%			
16	Other (Renewable)	97			97	100.00%			
17	APS Proposed Annualized Amount	1,802	9,566	11,368	1,793		9,267	96.88%	11,060
18	**AECC Adjustment**	**(858)**	**(4,794)**	**(5,653)**	**(854)**		**(4,645)**		**(5,499)**

Data Sources:

1. Barbara Lockwood's PTYP workpapers by Function & Elizabeth Blankenship's PTYP Additions Income Statement Pro Forma workpaper.
2. EAB-WP20DR Schedule C-2.

EXHIBIT KCH-4

AECC Existing Plant Rate Base Adjustment

Rate Base Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Existing Plant Rate Base**
AECC Adjustment Reflects Average TY Existing Plant Rate Base Amount.

Line No.	Description (a)	AECC Total Company Amount (b)	ACC Jurisdictional Allocation Factor (c)	AECC ACC Jurisdictional Amount (d)	Source (e)
1	Gross Utility Plant in Service	$ 0		$ 0	
2	Less: Accumulated Depreciation & Amort.	(273,746)	Various	(272,418)	See Page 2, Ln. 16, Col. (f).
3	Net Utility Plant in Service	273,746		272,418	= Ln. 1 - Ln. 2
4	Less: Total Deductions	(3,954)	99.76%	(3,945)	See Page 2, Ln. 21, Col. (b).
5	Total Additions	0		0	
6	Total Rate Base	$ 277,700		$ 276,363	= Ln. 3 - Ln. 4 + Ln. 5
	Original Cost Impact				
7	APS Requested Rate of Return			7.41%	
8	Required Operating Income			20,479	= Ln. 6 x Ln. 7
9	Gross Revenue Conversion Factor			1.3288	
10	Estimated Revenue Requirement Impact			$ 27,213	= Ln. 8 x Ln. 9
	Fair Value Impact				
11	Fair Value Return Before Adjustment			5.56%	
12	Fair Value Return After Adjustment			5.60%	
13	Change in Fair Value Return			0.04%	
14	Fair Value Rate Base Before Adjustment			$ 11,930,385	
15	Fair Value Rate Base After Adjustment			$ 12,208,457	
16	Change in Fair Value Rate Base			$ 278,071	= Ln. 15 - Ln. 14
17	Fair Value Required Operating Income Impact from FV Return Change			$ 4,773	= Ln. 14 x Ln. 13
18	Fair Value Required Operating Income Impact from FV Rate Base Change			$ 15,572	= Ln. 16 x Ln. 12
19	Total Fair Value Required Operating Income Impact			$ 20,345	= Ln. 17 + Ln. 18
20	Incremental Fair Value Operating Income Impact			(134)	= Ln. 19 - ln. 8
21	Gross Revenue Conversion Factor			1.3288	
22	Estimated Fair Value Revenue Requirement Impact			(178)	= Ln. 20 x Ln. 21
23	Total Revenue Requirement Impact			27,035	= Ln. 10 + Ln. 22

AECC Recommended Rate Base Adjustments
to Reflect Average TY Existing Plant Rate Base.
($000s)

AECC Existing Plant Accumulated Depreciation & Amortization Adjustment[1]

		Total Company (OCRB)				
	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Month	Production	Distribution	Gen'l & Int.	Elec. Plt Acq. Adj.	Total
1	Jun-19	3,476,104	1,808,365	1,009,336	49,384	6,343,189
2	Jun-20	3,498,716	1,821,929	1,019,691	50,290	6,390,626
3	Aug-19	3,521,327	1,835,493	1,030,046	51,196	6,438,062
4	Sep-19	3,543,939	1,849,057	1,040,401	52,102	6,485,499
5	Oct-19	3,566,550	1,862,621	1,050,756	53,008	6,532,935
6	Nov-19	3,589,162	1,876,185	1,061,111	53,914	6,580,372
7	Dec-19	3,611,773	1,889,749	1,071,466	54,820	6,627,808
8	Jan-20	3,634,385	1,903,313	1,081,821	55,726	6,675,245
9	Feb-20	3,656,996	1,916,877	1,092,176	56,633	6,722,681
10	Mar-20	3,679,608	1,930,441	1,102,531	57,539	6,770,118
11	Apr-20	3,702,220	1,944,005	1,112,886	58,445	6,817,554
12	May-20	3,724,831	1,957,568	1,123,241	59,351	6,864,991
13	Jun-20	3,747,443	1,971,132	1,133,596	60,257	6,912,428
14	13-Mo. Avg.	3,611,773	1,889,749	1,071,466	54,820	6,627,808
15	APS Proposed Amount	3,747,443	1,971,132	1,133,596	49,384	6,901,554
16	**AECC Adjustment**	**(135,669)**	**(81,383)**	**(62,130)**	**5,437**	**(273,746)**

AECC Existing Plant Accumulated Deferred Income Tax Adjustment[2]

Line No.	Month	Total Company (OCRB) Production
	(a)	(b)
17	Balance as of Jun. 2019	1,908,074
18	Balance as of Jun. 2020	1,911,966
19	Beg./End. Avg.	1,910,020
20	APS Proposed Amount[3]	1,913,974
21	**AECC Adjustment**	**(3,954)**

Data Sources:

1. Elizabeth Blankenship's Schedule B-1 workpaper; Elizabeth Blankenship's Pro Forma Depreciation Expense workpaper, & APS 2019 Q2 FERC Form 1.

2. Elizabeth Blankenship's Schedule B-1 workpaper & PTYP Additions Pro Forma Rate Base workpaper.

Note 3: The APS Post-TY Plant Additions Rate Base workpaper appears to have a formulaic error in the ADIT calculation for existing plant in the general & intangible function.

EXHIBIT KCH-5

AECC West Phoenix 4 Regulatory Disallowance Adjustment

Rate Base Impact
(Thousands of Dollars)

Pro Forma Adjustment: **West Phoenix 4 Regulatory Disallowance**
AECC Adjustment Reflects Average West Phoenix 4 Rate Base Amount.

Line No.	Description (a)	AECC Total Company Amount (b)	ACC Jurisdictional Allocation Factor (c)	AECC ACC Jurisdictional Amount (d)	Source (e)
1	Gross Utility Plant in Service	$ 0		$ 0	
2	Less: Accumulated Depreciation & Amort.	(164)	99.52%	(163)	See Page 2, Ln. 5, Col. (b).
3	Net Utility Plant in Service	164		163	= Ln. 1 - Ln. 2
4	Less: Total Deductions	(47)	99.76%	(47)	See Page 2, Ln. 10, Col. (b).
5	Total Additions	0		0	
6	Total Rate Base	$ 211		$ 210	= Ln. 3 - Ln. 4 + Ln. 5
	Original Cost Impact				
7	APS Requested Rate of Return			7.41%	
8	Required Operating Income			16	= Ln. 6 x Ln. 7
9	Gross Revenue Conversion Factor			1.3288	
10	Estimated Revenue Requirement Impact			$ 21	= Ln. 8 x Ln. 9
	Fair Value Impact				
11	Fair Value Return Before Adjustment			5.60%	
12	Fair Value Return After Adjustment			5.60%	
13	Change in Fair Value Return			0.00%	
14	Fair Value Rate Base Before Adjustment			$ 12,208,457	
15	Fair Value Rate Base After Adjustment			$ 12,208,667	
16	Change in Fair Value Rate Base			$ 210	= Ln. 15 - Ln. 14
17	Fair Value Required Operating Income Impact from FV Return Change			$ (0)	= Ln. 14 x Ln. 13
18	Fair Value Required Operating Income Impact from FV Rate Base Change			$ 12	= Ln. 16 x Ln. 12
19	Total Fair Value Required Operating Income Impact			$ 11	= Ln. 17 + Ln. 18
20	Incremental Fair Value Operating Income Impact			(5)	= Ln. 19 - ln. 8
21	Gross Revenue Conversion Factor			1.3288	
22	Estimated Fair Value Revenue Requirement Impact			(6)	= Ln. 20 x Ln. 21
23	Total Revenue Requirement Impact			15	= Ln. 10 + Ln. 22

AECC Recommended Rate Base Adjustments
to Reflect Average TY West Phoenix 4 Rate Base.
($000s)

AECC West Phoenix 4 Reg. Disallowance Accumulated Depreciation & Amortization Adjustment[1]

Line No.	Month	Total Company (OCRB) Production
	(a)	(b)
1	Balance as of Jun. 2019	(6,432)
2	Balance as of Jun. 2020	(6,761)
3	Beg./End. Avg.	(6,596)
4	APS Proposed Amount	(6,432)
5	**AECC Adjustment**	**(164)**

AECC West Phoenix 4 Reg. Disallowance Accumulated Deferred Income Tax Adjustment[1]

Line No.	Month	Total Company (OCRB) ADIT
	(a)	(b)
6	Balance as of Jun. 2019	(1,514)
7	Balance as of Jun. 2020	(1,584)
8	Beg./End. Avg.	(1,549)
9	APS Proposed Amount	(1,502)
10	**AECC Adjustment**	**(47)**

Data Sources:
1. EAB-WP9DR RB - WPhx4 Disallowance Pro Forma

EXHIBIT KCH-6

AECC Recent Deferrals Adjustment

Rate Base Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Recent Deferrals Adjustment**
AECC Adjustment Reflects Average Rate Base Amount for Recent Deferrals.

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	Gross Utility Plant in Service	$ 0		$ 0	
2	Less: Accumulated Depreciation & Amort.	0		0	
3	Net Utility Plant in Service	0		0	= Ln. 1 - Ln. 2
4	Less: Total Deductions	(2,093)	Various	(2,083)	See Page 2, Ln. 2, Cols. (h) + (i) + (j)
5	Total Additions	(8,457)	Various	(8,415)	See Page 2, Ln. 4, Cols. (h) + (i) + (j)
6	Total Rate Base	$ (6,364)		$ (6,332)	= Ln. 3 - Ln. 4 + Ln. 5
	Original Cost Impact				
7	APS Requested Rate of Return			7.41%	
8	Required Operating Income			(469)	= Ln. 6 x Ln. 7
9	Gross Revenue Conversion Factor			1.3288	
10	Estimated Revenue Requirement Impact			$ (623)	= Ln. 8 x Ln. 9
	Fair Value Impact				
11	Fair Value Return Before Adjustment			5.60%	
12	Fair Value Return After Adjustment			5.59%	
13	Change in Fair Value Return			-0.01%	
14	Fair Value Rate Base Before Adjustment			$ 12,208,644	
15	Fair Value Rate Base After Adjustment			$ 12,202,312	
16	Change in Fair Value Rate Base			$ (6,332)	= Ln. 15 - Ln. 14
17	Fair Value Required Operating Income Impact from FV Return Change			$ (1,221)	= Ln. 14 x Ln. 13
18	Fair Value Required Operating Income Impact from FV Rate Base Change			$ (354)	= Ln. 16 x Ln. 12
19	Total Fair Value Required Operating Income Impact			$ (1,575)	= Ln. 17 + Ln. 18
20	Incremental Fair Value Operating Income Impact			(1,106)	= Ln. 19 - ln. 8
21	Gross Revenue Conversion Factor			1.3288	
22	Estimated Fair Value Revenue Requirement Impact			(1,470)	= Ln. 20 x Ln. 21
23	Total Revenue Requirement Impact			(2,093)	= Ln. 10 + Ln. 22

AECC Recommended Adjustment to APS's Requested Recent Deferrals

Line No.	Description	AECC Recommended: Property Tax Deferral	AECC Recommended: Ocotillo Deferral	AECC Recommended: Four Corners SCR Deferral	APS Requested: Property Tax Deferral[1]	APS Requested: Ocotillo Deferral[3,4]	APS Requested: Four Corners SCR Deferral[5,6]	Adjustment: Property Tax Deferral	Adjustment: Ocotillo Deferral	Adjustment: Four Corners SCR Deferral	ACC Jurisdictional Allocators[7]: Property Tax Deferral	ACC Jurisdictional Allocators[7]: Ocotillo Deferral	ACC Jurisdictional Allocators[7]: Four Corners SCR Deferral
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate Base Deductions:												
2	Accumulated Deferred Income Taxes	(1,387,932)	21,600,827	19,282,623	(1,460,981)	22,744,956	20,304,711	73,049	(1,144,129)	(1,022,087)	100.00%	99.52%	99.52%
3	Rate Base Additions:												
4	Regulatory Assets/(Liabilities)	(5,607,805)	87,276,071	77,909,589	(5,902,953)	91,898,813	82,039,235	295,148	(4,622,742)	(4,129,646)	100.00%	99.52%	99.52%
5	Net Rate Base Adjustment	(4,219,873)	65,675,243	58,626,966	(4,441,972)	69,153,857	61,734,525	222,099	(3,478,613)	(3,107,559)			

Line No.	AECC Adjustment Detail:	Property Tax Deferral	Ocotillo Deferral	Four Corners SCR Deferral	
	(a)	(b)	(c)	(d)	
6	Beginning Balance	(5,902,953)	91,898,813	82,039,235	
7	APS Proposed Year 1 Amortization Amount[2,4,6]	(590,295)	9,245,484	8,259,293	<=== Based on APS's Proposed 10 Year Amortization Period.
8	Year 1 Ending Balance	(5,312,658)	82,653,328	73,779,943	
9	Beg./End. Avg Balance	(5,607,805)	87,276,071	77,909,589	

Data Sources:

1. **EAB-WP10DR RB - Include Property Tax Deferral.**
2. **EAB-WP42DR IS - PTAX Deferral Pro Forma.**
3. **EAB-WP12DR RB - Ocotillo Deferral Pro Forma**
4. **EAB-WP27DR IS - Ocotillo Deferral Pro Forma.**
5. **EAB-WP13DR RB - Four Corners SCR Deferral Pro Forma.**
6. **EAB-WP26DR IS - Four Corners SCR Deferral Pro Forma.**
7. **EAB-WP6DR Schedule B-2.**

EXHIBIT KCH-7

AECC Pension & OPEB Assets and Liabilities Adjustment

Rate Base Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Pension & OPEB Assets and Liabilities Adjustment**
AECC Adjustment Removes the Pension & OPEB Assets and Liabilities from Rate Base.

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	Gross Utility Plant in Service	$ 0		$ 0	
2	Less: Accumulated Depreciation & Amort.	-		-	
3	Net Utility Plant in Service	-		-	= Ln. 1 - Ln. 2
4	Less: Total Deductions	(510,776)	91.80%	(468,888)	See Page 2, Ln. 10
5	Total Additions	(765,519)	91.80%	(702,739)	See Page 2, -Ln. 9
6	Total Rate Base	$ (254,743)		$ (233,852)	= Ln. 3 - Ln. 4 + Ln. 5
	Original Cost Impact				
7	APS Requested Rate of Return			7.41%	
8	Required Operating Income			(17,328)	= Ln. 6 x Ln. 7
9	Gross Revenue Conversion Factor			1.3288	
10	Estimated Revenue Requirement Impact			$ (23,025)	= Ln. 8 x Ln. 9
	Fair Value Impact				
11	Fair Value Return Before Adjustment			5.59%	
12	Fair Value Return After Adjustment			5.56%	
13	Change in Fair Value Return			-0.03%	
14	Fair Value Rate Base Before Adjustment			$ 12,202,347	
15	Fair Value Rate Base After Adjustment			$ 11,968,496	
16	Change in Fair Value Rate Base			$ (233,852)	= Ln. 15 - Ln. 14
17	Fair Value Required Operating Income Impact from FV Return Change			$ (3,661)	= Ln. 14 x Ln. 13
18	Fair Value Required Operating Income Impact from FV Rate Base Change			$ (13,002)	= Ln. 16 x Ln. 12
19	Total Fair Value Required Operating Income Impact			$ (16,663)	= Ln. 17 + Ln. 18
20	Incremental Fair Value Operating Income Impact			665	= Ln. 19 - ln. 8
21	Gross Revenue Conversion Factor			1.3288	
22	Estimated Fair Value Revenue Requirement Impact			884	= Ln. 20 x Ln. 21
23	Total Revenue Requirement Impact			(22,141)	= Ln. 10 + Ln. 22

AECC Pension and OPEB Rate Base Adj. Detail

Line No.		Adjusted Test Year Ended 6/30/2019 Total Company	Adjusted Test Year Ended 6/30/2019 ACC
1	Underfunded Pension Liability [1]	(305,207)	(280,177)
2	Overfunded OPEB Asset [1]	52,611	48,297
3	Deferred Tax Asset Related to Pension & OPEB Funded Status [1]	78,510	72,071
4	Pension Unrecognized Loss Asset [2]	712,908	654,442
5	Deferred Tax Liability Related to Pension Unrecognized Loss Asset [2]	(176,445)	(161,975)
6	OPEB Prior Service Credit/Unrecognized Loss Liability [3]	(143,035)	(131,305)
7	Deferred Tax Asset Related to OPEB Prior SC/Unrecognized Loss [3]	35,401	32,498
8	Net Pension & OPEB Assets/Liabilities	254,743	233,852
9	Total Additions	765,519	702,739
10	Total Deductions	(510,776)	(468,888)
11	Jurisdictional Allocator	91.80%	

Data Sources:
1. EAB-WP5DR Schedule B-1; Schedule B-1, lines 8 and 20.
2. EAB-WP5DR Schedule B-1, Reg Asset Liability tab, line 1.
3. EAB-WP5DR Schedule B-1, Reg Asset Liability tab, line 28.

EXHIBIT KCH-8

AECC Pension & OPEB Expense Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Pension & OPEB Expense**
AECC Adjustment to Reflect Jul. 2019 - Jun. 2020 Pension & OPEB expense.

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$ 0		$ 0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense	($14,001)	91.80%	($12,852)	See Page 2, Ln. 14, Col. (d).
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	$ (14,001)		$ (12,852)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 14,001		$ 12,852	= Ln. 5 - Ln. 11
13	Income Taxes	3,464		3,180	= 24.745% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 10,536**		**$ 9,672**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	**$0**		**$0**	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 10,536		$ 9,672	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	**$0**		**$0**	= Sum (Lns. 23:26)
28	Net Income	$ 10,536		$ 9,672	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.3288	
30	Estimated Revenue Requirement Impact			$\boxed{\textbf{(12,852)}}$	= Ln. 28 x Ln. 29

AECC Pension & OPEB Expense Adjustment Derivation
(Thousands of Dollars)

Line No.	Description	APS Proposed Total Company TY Pension & OPEB Exp. Adjustment [1]	AECC Recommended Total Company TY Pension & OPEB Exp. Adjustment [2]	Incremental AECC Recommended Total Company TY Pension & OPEB Exp. Adjustment [3]
	(a)	(b)	(c)	(d)
	Electric Operating Revenues			
1	Revenues from Base Rates	$ -	$ -	$ -
2	Revenues from Surcharges	-	-	-
3	Other Electric Revenues	-	-	-
4	Total Electric Operating Revenues	-	-	-
5	Electric Fuel and Purchased Power Costs	-	-	-
6	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-
	Other Operating Expenses:			
7	Operations Excluding Fuel Expense	11,251	(2,750)	(14,001)
8	Maintenance	-	-	-
9	Subtotal	11,251	(2,750)	(14,001)
10	Depreciation and Amortization	-	-	-
11	Amortization of Gain	-	-	-
12	Administrative and General	-	-	-
13	Other Taxes	-	-	-
14	Total Other Operating Expense	11,251	(2,750)	(14,001)
15	Operating Income Before Income Tax	(11,251)	2,750	14,001
16	Interest Expense	-	-	-
17	Taxable Income	(11,251)	2,750	14,001
18	Current Income Tax Rate - 24.75% (line 17 * 24.75%)	(2,785)	681	3,466
19	Operating Income (line 15 minus line 18)	$ (8,466)	$ 2,069	$ 10,535

Adjustment to Test Year operations to reflect Jul. 2019 - Jun. 2020 pension & OPEB expense.

Data Sources:
1. EAB-WP36DR IS - Normalize Employee Benefits Pro Forma.
2. Based on 50% of 2019 expense and 50% of 2020 expense from on APS's response to Data Request AECC 24.1, Attachment ExcelAPS19RC02051.
3. Column (c) - Column (b).

EXHIBIT KCH-9

AECC Pro Forma Test-Year Payroll Expense Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Pro Forma Test-Year Payroll Expense**
AECC Adjustment to Reflect Pro Forma Payroll Increase Amount

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$ 0		$ 0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense	($1,588)	Various	($1,458)	See Page 2, Ln. 11, Col. (e).
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	$ (1,588)		$ (1,458)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 1,588		$ 1,458	= Ln. 5 - Ln. 11
13	Income Taxes	393		361	= 24.745% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 1,195**		**$ 1,097**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	**$0**		**$0**	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 1,195		$ 1,097	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	**$0**		**$0**	= Sum (Lns. 23:26)
28	Net Income	$ 1,195		$ 1,097	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.3288	
30	Estimated Revenue Requirement Impact			**$ (1,458)**	= Ln. 28 x Ln. 29

Test Year Payroll Expense

Pro Forma Support
Payroll Expense O&M Split

	(a)	(b)	(c)	(d)	(e)
Line No.	**Base Payroll**		**APS Calc**	**AECC Calc**	**AECC Adjustment**
1	Test Year-O&M		304,071,784	304,071,784	-
2	Annualized		303,672,035	302,388,057	(1,283,977)
3	Base Payroll Difference Total		(399,749)	(1,683,726)	(1,283,977)
4	**Payroll Taxes**	7.0%	(27,982)	(117,861)	(89,878)
5	**Benefits**				
6	Group Ins.	13.0%	(51,958)	(218,846)	(166,888)
7	Employee Savings	3.7%	(14,718)	(61,990)	(47,273)
8	Pension	0.0%	-	-	-
9	OPEB	0.0%	-	-	-
10	Total Taxes & Benefits	23.7%	(94,658)	(398,697)	(304,039)
11	**Base, Tax and Benefits Total**		**(494,407)**	**(2,082,423)**	**(1,588,016)**
12	O&M Split by Type				
13	Wage/Headcount Change		(2,611,762)	(2,611,762)	-
14	Union 387 Increase		2,117,355	529,339	(1,588,016)
15	Union SPF Increase		-	-	-
16	Total		(494,407)	(2,082,423)	(1,588,016)
17	O&M Split by FERC Form 1*	Share			
18	Operations	82.93%	(409,996) **[A]**	(1,726,886)	(1,316,890)
19	Maintenance	17.07%	(84,411) **[B]**	(355,537)	(271,126)
20	Total		(494,407)	(2,082,423)	(1,588,016)

* Using FERC Form 1 ratio FERC Form 1 includes all forms of Salaries and Wages not just Base Payroll.

EXHIBIT KCH-10

AECC Cash Incentive Expense Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Cash Incentive Expense Adjustment**
AECC Adjustment to Remove Cash Incentive Related to Financial Performance

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$ 0		$ 0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense	($22,182)	91.80%	($20,363)	See Page 2, Ln. 14, Col. (d).
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	$ (22,182)		$ (20,363)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 22,182		$ 20,363	= Ln. 5 - Ln. 11
13	Income Taxes	5,489		5,039	= 24.745% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 16,693**		**$ 15,324**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	**$0**		**$0**	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 16,693		$ 15,324	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	**$0**		**$0**	= Sum (Lns. 23:26)
28	Net Income	$ 16,693		$ 15,324	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.3288	
30	Estimated Revenue Requirement Impact			**(20,362)**	= Ln. 28 x Ln. 29

AECC Cash Incentive Expense Adjustment Derivation
(Thousands of Dollars)

Line No.	Description	APS Proposed Total Company TY Cash Incentive Adjustment	AECC Recommended Total Company TY Cash Incentive Adjustment	Incremental AECC Recommended Total Company TY Cash Incentive Adjustment
	(a)	(b)	(c)	(d)
	Electric Operating Revenues			
1	Revenues from Base Rates	$ -	$ -	$ -
2	Revenues from Surcharges	-	-	-
3	Other Electric Revenues	-	-	-
4	Total Electric Operating Revenues	-	-	-
5	Electric Fuel and Purchased Power Costs	-	-	-
6	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-
	Other Operating Expenses:			
7	Operations Excluding Fuel Expense	4,153	(9,929)	(14,082)
8	Maintenance	126	(243)	(369)
9	Subtotal	4,279	(10,172)	(14,451)
10	Depreciation and Amortization	-	-	-
11	Amortization of Gain	-	-	-
12	Administrative and General	1,327	(6,404)	(7,731)
13	Other Taxes	-	-	-
14	Total Other Operating Expense	5,606	(16,576)	(22,182)
15	Operating Income Before Income Tax	(5,606)	16,576	22,182
16	Interest Expense	-	-	-
17	Taxable Income	(5,606)	16,576	22,182
18	Current Income Tax Rate - 24.750% (line 17 * 24.75%)	(1,387)	4,103	5,490
19	Operating Income (line 15 minus line 18)	$ (4,219)	$ 12,473	$ 16,692

Adjustment to Test Year operations to remove cash incentive related to financial performance, normalized over a 3 year period.

Derivation of AECC Cash Incentive Adjustment

(Thousands of Dollars)

	Total Cash Incentive Expense Total Company					Estimated Non-Financial Performance Portion [3] Total Company				
	2017 [1]	2018 [1]	Jul. - Dec. 2018 [2]	Jan.-Jun. 2019 [2]	TY 2019 [1]	2017	2018	Jul. - Dec. 2018	Jan.-Jun. 2019	TY 2019
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Account										
500	0	0	0	0	0	0	0	0	0	0
506	5,581	3,700	1,830	1,313	3,143	2,454	1,624	803	758	1,561
510	0	0	0	0	0	0	0	0	0	0
517	0	0	0	0	0	0	0	0	0	0
519	1,077	715	409	293	702	474	314	179	169	349
524	9,694	6,433	3,677	2,640	6,317	4,262	2,824	1,614	1,523	3,137
549	2,538	2,428	1,252	898	2,150	1,116	1,066	549	518	1,068
557	787	691	320	230	550	346	303	141	133	273
566	2,550	1,979	965	693	1,658	1,121	869	424	400	823
586	0	0	0	0	0	0	0	0	0	0
588	7,057	5,313	2,795	2,006	4,801	3,103	2,332	1,227	1,158	2,384
593	0	0	0	0	0	0	0	0	0	0
598	0	0	0	0	0	0	0	0	0	0
903	2,475	2,630	1,273	913	2,186	1,088	1,154	559	527	1,086
908	0	0	0	0	0	0	0	0	0	0
916	902	794	435	312	747	397	349	191	180	371
920	17,412	16,041	8,522	6,117	14,639	7,656	7,041	3,741	3,530	7,270
926	132	70	55	39	94	58	31	24	23	47
928	865	349	204	146	350	380	153	89	84	174
930.2	1,383	1,296	665	478	1,143	608	569	292	276	568
	52,453	42,439	22,401	16,079	38,480	23,063	18,628	9,832	9,278	19,110
Participant A&G Credit (net APS A&G)	(4,021)	(3,741)	(1,935)	(1,389)	(3,324)	(1,768)	(1,642)	(849)	(801)	(1,651)
Net O&M Incentive	48,432	38,698	20,466	14,690	35,156	21,295	16,986	8,983	8,476	17,459
Company Performance [4]	20,421	18,557	9,796	3,708	13,504					
Business Performance	32,032	23,882	12,606	12,370	24,976					
Shareholder Value % of Business Per. [5]	28.0%	22.0%	22.0%	25.0%						
Total Financial Performance Portion	29,390	23,811	12,569	6,801	19,370					
Total Non-Financial Performance Portion	23,063	18,628	9,832	9,278	19,110					
Total Non-Financial Performance Proportion	44.0%	43.9%	43.9%	57.7%	49.7%					
						AECC Adjustment to Test Year				
	Total APS	Operations	Maintenance	A&G		Total APS	Operations	Maintenance	A&G	
3 Year Average	40,762	25,857	676	14,229		18,580	11,775	307	6,498	
Less TY 2019 Incentive Amount	35,156	21,704	550	12,902		35,156	21,704	550	12,902	
Adjustment to Incentive	5,606	4,153	126	1,327		(16,576)	(9,929)	(243)	(6,404)	
						AECC Adjustment to APS Proposal				
						(22,182)	(14,082)	(369)	(7,731)	

Data Sources:
1. EAB-WP39DR IS - Normalize Cash Incentive.
2. Estimated from overall proportions from APS's response to Data Request AECC 16.1.
3. Estimated from derived overall non-financial proportions for each period.
4. 2017 and 2018 from APS's supplemental response to Data Request AECC 6.1 a. Test Year from APS's response to Data Request 16.1.
5. APS's response to Data Request AECC 16.2.

EXHIBIT KCH-11

AECC Pro Forma Customer Annualization Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Pro Forma Customer Annualization Adjustment**
AECC Adjustment to Reflect Customer Counts as of December 31, 2019

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates	$2,438	100.00%	$2,438	Page 2, Line 1.
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$ 2,438		$ 2,438	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power	$178	100.00%	$178	Page 2, Line 5.
8	Operations and Maintenance Excluding Fuel Expense				
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	$ 178		$ 178	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 2,260		$ 2,260	= Ln. 5 - Ln. 11
13	Income Taxes	559		559	= 24.745% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 1,701**		**$ 1,701**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	**$0**		**$0**	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 1,701		$ 1,701	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	**$0**		**$0**	= Sum (Lns. 23:26)
28	Net Income	$ 1,701		$ 1,701	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.3288	
30	Estimated Revenue Requirement Impact			$\boxed{\$ \quad (2,260)}$	= Ln. 28 x Ln. 29

AECC Customer Annualization Adjustment

Income Statement Pro Forma Adjustments
Test Year Ended 6/30/2019
(Dollars in Thousands)

Line No.	Description		
	Revenues		
1	Operating Revenue	$	2,438
2	Adjustment for Difference Between Customer Annualized Sales & Actual Sales (MWh)		5,535
	Fuel and Purchased Power Expenses		
3	Adjustment to Sales (MWh)		5,535
4	Test Year Fuel & Purchased Power Costs (¢/kWh)		3.2112
5	Proforma Adjustment to Fuel & Purchased Power Expenses ((Line 3 * Line 4)/100)	$	178
6	Operating Revenues Less Fuel & Purchased Power Expenses (Line 1 - Line 5)	$	2,260
7	Operating Income Before Income Tax	$	2,260
8	Income Tax at 24.75% (Line 7 * 24.75%)	$	559
9	Net Income (Line 7 - Line 8)	$	1,701

Adjustment to Test Year operating revenues to reflect the annualization of customer levels at 12/31/2019.

AECC Customer Annualization Adjustment Derivation

Annualized Customer Levels - Pro forma for December 31, 2019

(a)	(b)	(c)	(d)	(e)	(f)	(g)
						c × d + e × f
		Customer Annualization Proforma				
		summer customer proforma	summer customer proforma	winter customer proforma	winter customer proforma	total customer proforma
Rate Class	Rate Group	$/kwh	kWh	$/kwh	kWh	Revenue
R-XS	Basic XS	0.13579	63,589,000	0.14096	49,710,000	$ 15,641,872
R-BASIC	Basic	0.13794	(47,395,000)	0.14512	(32,216,000)	$ (11,212,852)
R-BASIC L	Basic L	0.14498	(42,991,000)	0.14972	(31,620,000)	$ (10,966,982)
TOU-E	TOU-E	0.14250	(77,166,378)	0.13098	(55,307,980)	$ (18,240,448)
R-2	TOU-D	0.12853	130,868,134	0.13676	89,918,848	$ 29,117,783
R-3	TOU-D	0.12118	72,672,585	0.10838	49,966,472	$ 14,221,830
R-TECH	TOU-D	0.13817	190,600	0.12654	131,699	$ 43,000
E-12 Solar Legacy	IB S	0.18151	463,000	0.15657	308,000	$ 132,263
ET-1 Solar Legacy	TOU-E S	0.11972	1,907,046	0.13724	1,320,523	$ 409,540
ET-2 Solar Legacy	TOU-E S	0.11781	1,664,331	0.13232	1,152,457	$ 348,568
ECT-2 Solar Legacy	TOU-D S	0.17550	(1,298,526)	0.17291	(900,359)	$ (383,572)
ECT-1R Solar Legacy	TOU-D S	0.16874	(5,971,793)	0.15756	(4,140,661)	$ (1,660,083)
E-20		0.12824	119,000	0.11892	64,000	$ 22,871
E-30		0.27048	(30,000)	0.25704	(29,000)	$ (15,569)
E-32 XS	E-32 XS	0.15349	15,126,707	0.14560	11,608,756	$ 4,012,033
E-32 XS D	E-32 XS	0.16307	3,801,293	0.15682	2,917,244	$ 1,077,359
E-32 S		0.13187	(8,553,000)	0.12154	(6,208,000)	$ (1,882,404)
E-32 M	E-32 M	0.11323	(15,366,000)	0.10073	(11,799,000)	$ (2,928,405)
E-32 L	E-32 L	0.09921	(50,150,000)	0.08703	(41,416,000)	$ (8,579,816)
E-32TOU XS		0.15946	882,000	0.14258	818,000	$ 257,274
E-32TOU S		0.13311	1,530,000	0.12214	1,278,000	$ 359,753
E-32TOU M		0.10323	6,347,000	0.08945	4,917,000	$ 1,095,026
E-32TOU L	E-32TOU L	0.09564	-	0.08324	-	$ -
E-34	GS-XL	0.07771	(70,059,000)	0.07771	(63,654,000)	$ (10,390,837)
E-35	GS-XL	0.07783	46,706,000	0.07783	42,436,000	$ 6,937,922
E-36			-		-	$ -
E-221		0.10081	(16,119,000)	0.10081	(9,959,000)	$ (2,628,923)
GS-S M		0.14390	1,417,000	0.13905	1,101,000	$ 357,000
GS-S L		0.12313	(674,000)	0.11619	(460,000)	$ (136,437)
E-47	SL	0.40913	-	0.40913	-	$ -
E-58	SL	0.33064	(4,244,265)	0.33048	(4,016,544)	$ (2,730,711)
E-59	SL	0.12440	223,382	0.12440	211,397	$ 54,087
E-67, OPA	OPA	0.05594	982,882	0.05594	930,147	$ 107,015
Contract 12	OPA	0.08798	-	0.08798	-	$ -
E-32M AG-1	E-32 M	0.06956	-	0.06438	-	$ -
E-32L AG-1	E-32 L	0.07668	-	0.08267	-	$ -
E-32LTOU AG-1	E-32TOU L	0.22952	-	0.26939	-	$ -
E-34 AG-1	GS-XL	0.07771	-	0.07771	-	$ -
E-35 AG-1	GS-XL	0.02373	-	0.02373	-	$ -
XHLF	GS-XL	0.06358	-	0.06358	-	$ -
Total			8,472,000		(2,937,000)	$ **2,438,157**
Residential			96,532,000		68,323,000	$ 17,450,919
General Service			(85,022,000)		(68,385,000)	$ (12,443,152)
Outdoor Lighting and OPA			(3,038,000)		(2,875,000)	$ (2,569,610)
			8,472,000		(2,937,000)	$ **2,438,157**

Res - Growth				
0.13579	63,589,000	0.14096	49,710,000	$ 15,641,872
0.13794	-	0.14512	-	$ -
0.14498	-	0.14972	-	$ -
0.14250	2,317,691	0.13098	1,075,684	$ 471,164
0.12853	19,307,627	0.13676	10,781,053	$ 3,956,026
0.12118	10,441,761	0.10838	5,821,032	$ 1,896,216
0.13817	21,942	0.12654	12,043	$ 4,556
0.18151	27,000	0.15657	46,000	$ 12,103
0.11972	131,524	0.13724	61,043	$ 24,124
0.11781	114,785	0.13232	53,274	$ 20,572
0.17550	(123,476)	0.17291	(66,643)	$ (33,193)
0.16874	(567,853)	0.15756	(306,485)	$ (144,109)
				$ 21,849,330

Res - Rate Change				
0.13579	-	0.14096	-	$ -
0.13794	(47,395,000)	0.14512	(32,216,000)	$ (11,212,852)
0.14498	(42,991,000)	0.14972	(31,620,000)	$ (10,966,982)
0.14250	(79,484,069)	0.13098	(56,383,663)	$ (18,711,612)
0.12853	111,560,508	0.13676	79,137,795	$ 25,161,757
0.12118	62,230,824	0.10838	44,145,440	$ 12,325,614
0.13817	168,658	0.12654	119,657	$ 38,445
0.18151	436,000	0.15657	262,000	$ 120,160
0.11972	1,775,522	0.13724	1,259,481	$ 385,417
0.11781	1,549,547	0.13232	1,099,183	$ 327,996
0.17550	(1,175,050)	0.17291	(833,716)	$ (350,379)
0.16874	(5,403,940)	0.15756	(3,834,176)	$ (1,515,973)
				$ (4,398,410)

Based on Dec. 2019 customer counts from APS's response to Data Request AECC 18.1, attachment ExcelAPS19RC01262.
AECC's adjustment excludes Special Contracts, E-36 XL, and non-E-211 Irrigation customers, consistent with APS's adjustment.
APS provided the workpaper supporting its Customer Annualization adjustment in its response to Data Request AECC 1.1, attachment APS19RC00379.

EXHIBIT KCH-12

Vertically Integrated Electric Utility Rate Case Summary
12 Months Ended June 30, 2020
Cases with ROE Determinations
As Reported by Regulatory Research Associates, a group within S&P Global Market Intelligence

Line No.	Decision Date	State	Company	Case Identification	Common Equity/ Total Capital (%)	Return on Equity (%)
1	8/29/2019	Vermont	Green Mountain Power Corp.	C-19-1932-TF	49.46	9.06
2	9/4/2019	Wisconsin	Northern States Power Co - WI	D- 4220-UR-124 (Elec)	52.52	10.00
3	10/31/2019	Wisconsin	Wisconsin Electric Power Co.	D-05-UR-109 (WEP-Elec)	54.46	10.00
4	10/31/2019	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-126 (Elec)	51.96	10.00
5	11/7/2019	Louisiana	Entergy New Orleans LLC	D-UD-18-07 (elec.)	50.00	9.35
6	11/29/2019	Idaho	Avista Corp.	C-AVU-E-1904	50.00	9.50
7	12/4/2019	Indiana	Northern IN Public Svc Co.	Ca-45159	47.86	9.75
8	12/17/2019	Georgia	Georgia Power Co.	D-42516	56.00	10.50
9	12/19/2019	California	San Diego Gas & Electric Co.	A-19-04-017 (Elec)	52.00	10.20
10	12/19/2019	California	Pacific Gas and Electric Co.	A-19-04-015	52.00	10.25
11	12/19/2019	California	Southern California Edison Co.	A-19-04-014	52.00	10.30
12	12/20/2019	Arkansas	Southwestern Electric Power Co	D-19-008-U	33.71	9.45
13	12/20/2019	Montana	NorthWestern Corp.	D2018.2.12	49.38	9.65
14	12/24/2019	Nevada	Sierra Pacific Power Co.	D-19-06002	50.92	9.50
15	1/8/2020	Iowa	Interstate Power & Light Co.	D-RPU-2019-0001	51.00	10.02
16	1/23/2020	Michigan	Indiana Michigan Power Co.	C-U-20359	46.56	9.86
17	2/6/2020	California	PacifiCorp	A-18-04-002	51.96	10.00
18	2/11/2020	Colorado	Public Service Co. of CO	D-19AL-0268E	55.61	9.30
19	2/24/2020	North Carolina	Virginia Electric & Power Co.	E-22, Sub 562	52.00	9.75
20	3/11/2020	Indiana	Indiana Michigan Power Co.	Ca-45235	37.55	9.70
21	3/25/2020	Washington	Avista Corp.	D-UE-190334	48.50	9.40
22	4/27/2020	Kentucky	Duke Energy Kentucky Inc.	C-2019-00271	48.23	9.25
23	5/8/2020	Michigan	DTE Electric Co.	C-U-20561	38.32	9.90
24	5/20/2020	New Mexico	Southwestern Public Service Co	C-19-00170-UT	54.77	9.45
25	6/29/2020	Indiana	Duke Energy Indiana, LLC	Ca-45253	40.98	9.70
26				MEDIAN:		**9.75**
27				MEAN:		9.75
28				OBSERVATIONS:		25

EXHIBIT KCH-13

AECC Navajo Unrecovered Plant Costs Regulatory Asset Return Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Pro Forma Navajo Return Adjustment**
AECC Adjustment Applies a Reduced Return Equal to APS's Cost of Long-Term Debt to the Navajo Regulatory Asset

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$ 0		$ 0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense	(2,559)	100.00%	(2,559)	Page 2, Line 7, Col. (b).
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	$ (2,559)		$ (2,559)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 2,559		$ 2,559	= Ln. 5 - Ln. 11
13	Income Taxes	633		633	= 24.745% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 1,926**		**$ 1,926**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	**$0**		**$0**	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 1,926		$ 1,926	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	**$0**		**$0**	= Sum (Lns. 23:26)
28	Net Income	$ 1,926		$ 1,926	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.3288	
30	Estimated Revenue Requirement Impact			**$ (2,559)**	= Ln. 28 x Ln. 29

AECC Navajo Unrecovered Power Plant Costs

Regulatory Asset Return Adjustment Derivation

(Thousands of Dollars)

Line No.		Account	As of 6/30/2019 Net Book Balance	Deferred Tax Liability Balance	Net Rate Base Balance
	(a)	(b)	(c)	(d)	(e)
1	Unrecovered Power Plant Costs-Navajo [1]	1823	82,833	(20,501)	62,332

Line No.		
2	WACC with ROE at Median - AECC Adjusted [2]	7.19%
3	APS Cost of Debt [3]	4.10%
4	AECC Return Adjustment	-3.09%
5	AECC After-Tax Return Adj. on Net Rate Base	(1,926)
6	Gross Revenue Conversion Factor	1.3288
7	AECC Return Adj. Revenue Requirement Impact	(2,559)

Data Sources:

1. EAB-WP5DR Schedule B-1, "Reg Asset Liab" tab, Line. No. 3.

2. AECC Exhibit KCH-1, p. 2.

3. APS Standard Filing Requirements, Exhibit D-1, p. 1 of 2.

EXHIBIT KCH-14

AECC Demand Side Management Expense Transfer to DSMAC Adjustment

Base Rate Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **DSM Base Rate Adjustment**
AECC Adjustment to Transfer DSM Expenses from Base Rates to the DSMAC

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$ 0		$ 0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense	($20,000)	100.00%	($20,000)	LRS_WP11DR, Ln. 1382.
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	$ (20,000)		$ (20,000)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 20,000		$ 20,000	= Ln. 5 - Ln. 11
13	Income Taxes	4,949		4,949	= 24.745% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 15,051**		**$ 15,051**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	**$0**		**$0**	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 15,051		$ 15,051	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	**$0**		**$0**	= Sum (Lns. 23:26)
28	Net Income	$ 15,051		$ 15,051	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.3288	
30	Estimated Revenue Requirement Impact			**$ (20,000)**	= Ln. 28 x Ln. 29

EXHIBIT KCH-15

Exhibit KCH-15

APS's Responses to Data Requests
Referenced in the
Revenue Requirement
Direct Testimony/Exhibits
of Kevin C. Higgins

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
SIXTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 26, 2020

AECC 6.1: **Cash Incentive.** Please refer to Ms. Blankenship's workpaper EAB-WP39DR IS-Normalize Cash Incentive. Regarding the cash incentive for each year 2017, 2018, and 2019 of $52,453(000), $42,439(000), and $38,480(000), respectively, please provide:

a. The actual expense amount or proportion attributable to each of the following components: APS Performance Component, Business Unit Performance Component, and (if applicable) the Individual Performance Component.

b. The actual proportion of the Business Unit Performance Component expense attributable to i.) Shareholder Value or ii.) any other metric related to financial performance (please identify the metric[s]).

c. If applicable, the actual proportion of the Individual Performance Component expense attributable to i.) Shareholder Value or ii.) any other metric related to financial performance (please identify the metric[s]).

Response:

a. Individual incentives are calculated based on the financial performance of APS (50%), the business unit performance (50%) and the individual performance as described in Incentive Plan Documents provided in APS Initial 1.15. The last of these affect individual amounts but do not change the total amount of incentives. The incentive results are summarized by Business Unit and the expense is allocated in the same proportion as labor costs were charged during the year. The expense recorded also includes the payroll tax estimate and retroactive overtime applicable to the cash incentive. Incentives are not recorded at the Individual Performance Component level.

b. The Business Unit Performance Component composition is described in the Incentive Plan Documents. Incentives are not recorded at the Individual Performance Component level.

c. Not applicable. The Individual Performance Component is applied separately from the APS Performance and Business Unit Performance Component.

Witness: Elizabeth Blankenship

Supplemental Response:

a. Please see the table below for a breakout of the cash incentive dollars for 2017 and 2018.

	Company Performance	Business Performance	Total
	(dollars in thousands)		
2017	$ 20,421	$ 32,032	$ 52,453
2018	$ 18,557	$ 23,882	$ 42,439

The $38,480 is for the Test Year ending June 30, 2019, which contains a mix of 2018 & 2019 metrics. Incentive metrics are determined based on a calendar year, and therefore it is not meaningful to split out the test year total in this manner.

Witness: Elizabeth Blankenship

FREEPORT MINERALS CORPORATION AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION (COLLECTIVELY "AECC")'S EIGHTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 MARCH 6, 2020

AECC 8.7: **Payroll Annualization Adjustment.** Please refer to Ms. Elizabeth Blankenship's payroll expense workpaper EAB-WP35DR IS - Annualize Payroll Pro Forma.xlsx.

a. On the "Calc" worksheet, APS depicts a Union Increase of $1,711,970, a pasted value without a supporting calculation. Please provide a workpaper showing the derivation of this amount.

b. The labeling in the workpaper depicts the $1,711,970 entry as an "annualized" amount. Please explain exactly how annualization applies to this entry.

c. What is the implementation date(s) of the $1,711,970 union increase?

d. Was the union increase 2.5%? If not, please explain.

Response:

a. Please see the attached spreadsheet ExcelAPS19RC00945.

b. The "annualized" label refers to the base wage used to calculate the expected union wage increase of $1,711,970, which represents the total amount of the 2020 union wage increase.

c. The estimated date for the annual union increase is April 1, 2020.

d. APS used 2.5% as an estimate in the pro forma calculation based on the history of past union increases. Union negotiations are ongoing, and the union increase for 2020 has not yet been determined.

Witness: Elizabeth Blankenship

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
MARCH 10, 2020

AECC 10.1: **Pension Regulatory Asset.** Please refer to EAB-WP5DR, Schedule B-1 Work Paper, page 5, line 1.

a. Please state plainly (i.e., without reference to Footnote (a) in the work paper) why this item is included in rate base as a regulatory asset.

b. Does APS earn a return on this Pension regulatory asset in rate base? If so, what is the rationale for requiring customers to pay APS a return on this item? What benefit has been provided to customers from this regulatory asset?

c. Does this item represent unrecognized actuarial losses?

d. To the best of APS's knowledge, has the ACC explicitly addressed and approved the inclusion of this Pension regulatory asset in rate base for APS? If so, please cite the relevant order(s).

e. Referring to Footnote (a) in the workpaper: where does the offset that is reported in Other Comprehensive Income appear in APS's revenue requirement in this case? Please cite to schedules.

f. Is the $712.9 million amount a Total Electric or ACC jurisdictional amount? If the former, please provide the ACC jurisdictional amount. If the latter, please provide the Total Electric amount.

g. Please explain fully the relationship between the $712.9 million entry on line 1 to the $207.6 million entry provided in APS's Response to Initial 1.48(a). What is the conceptual relationship between these balances? Please reconcile these amounts.

Response: a) This regulatory asset account was created as a direct result of the Company's adoption of Accounting Standards Codification (ASC) 715 (Compensation – Retirement Benefits) on December 31, 2006. The funded status of pension and other postretirement benefit plan at December 31, 2006 is required by GAAP to be reported as an asset (for over-funded plans) or a liability (for under-funded plans) with the offset recorded to OCI (Other Comprehensive Income/Loss). The pension plan is under-funded and reported as a liability. FAS 71 accounting allows the regulated utility (APS) to establish a regulatory asset/liability to record the offset to the funded status adjustments instead of an offset to Other Comprehensive Income/Loss. Please see also APS's response to part (b).

Witness: Elizabeth Blankenship

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
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DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
MARCH 10, 2020

Response to AECC 10.1 (continued):

b) Yes, APS earns a return on the Pension regulatory asset in rate base similar to other items included in rate base. Please refer to the Commission precedents that allow APS to include the pension asset as a regulatory asset, Decision Nos. 69663, 71448, 73183 and 76295.

c) Yes, this amount represents unamortized net actuarial loss.

d) Please see APS's response to part b.

e) Per GAAP, the offset to the funded status adjustment is traditionally recorded to OCI. However, FAS 71 accounting allows the regulated utility (APS) to establish a regulatory asset/liability to record the offset to the funded status adjustment instead of OCI. The offset amount to pension underfunded status reported as liability is recorded as a regulatory asset instead of Other Comprehensive Loss.

f) The $712.9 million recorded for APS is a Total Company amount. Please see line 16 on Schedule B-1 for the total regulatory assets ACC jurisdiction amount.

g) The $207.6 million is the under-funded status at 06/30/2019 of the pension plan recorded as liability. $712.9 million is the unamortized portion of the actuarial loss. On a bi-annual basis, a year-end valuation is received from the actuary which calculates the funded status of all pension plans. Bi-annual adjustments for the valuation received from the actuary are recorded to the funded status liability with offset to the regulatory asset for APS share. Reconciliation at 06/30/2019 for these accounts is provided below.

	Amounts in millions	
Funded Status at 12/31/2018	$	(296.0)
January - June expense		(2.8)
Contribution		89.7
Mid-Year Adjustment		1.5
Total Funded Status at 06/30/2019		(207.6)
Regulatory asset at 12/31/2018	$	733.3
January - June amortization		(18.9)
Mid-Year Adjustment		(1.5)
Total Regulatory Asset at 06/30/2019		712.9

Witness: Elizabeth Blankenship

AECC 10.2: **Pension Regulatory Asset.** Please refer to EAB-WP5DR, Schedule B-1 Work Paper, page 5, line 1.

a. Does APS have a prepaid pension asset/liability (representing the cumulative difference between what APS has contributed to its pension plans and the cumulative actuarially-determined pension cost)? If so, please identify the amount, as well as any associated ADIT, on a Total Electric and ACC jurisdictional basis.

b. If APS has a prepaid pension asset/liability, is it included in rate base? If yes, please identify this in EAB-WP5DR, Schedule B-1 Work Paper or elsewhere in APS's filing.

c. Does the $712.9 million entry constitute (or otherwise include) a prepaid pension asset? If yes, are there other items included in this amount? If other items are included, please identify and state the amounts separately.

d. To the best of APS's knowledge, has the ACC explicitly addressed and approved the inclusion of a prepaid pension asset/liability in rate base for APS? If so, please cite the relevant order(s).

Response:

a. APS does not have a prepaid pension asset/liability.

b. N/A

c. The $712.9 million entry does not constitute a prepaid pension asset.

d. N/A

Witness: Elizabeth Blankenship

AECC 10.9: **Prepaid OPEB asset/liability**.

a. Does APS have a prepaid OPEB asset/liability (representing the cumulative difference between what APS has contributed to its OPEB plans and the cumulative actuarially-determined OPEB cost)? If so, please identify the amount, as well as any associated ADIT, on a Total Electric and ACC jurisdictional basis.

b. If APS has a prepaid OPEB asset/liability, is it included in rate base? If yes, please identify this in EAB-WP5DR, Schedule B-1 Work Paper or elsewhere in APS's filing.

c. To the best of APS's knowledge, has the ACC explicitly addressed and approved the inclusion of a prepaid OPEB asset/liability in rate base for APS? If so, please cite the relevant order(s).

Response:

a. APS does not have a prepaid OPEB asset/liability.

b. N/A

c. N/A

Witness: Elizabeth Blankenship

FREEPORT MINERALS CORPORATION AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S THIRTEENTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 MARCH 26, 2020

AECC 13.7: **Pension Asset**. Please refer to APS's response to AECC 10.1(b), which contends that Commission precedents allow APS to include the pension asset in rate base as a regulatory asset according to Decision Nos. 69663, 71448, 73183 and 76295. Admit that none of the cited orders contains an explicit discussion of, or reference to, the inclusion of the pension asset in rate base as a regulatory asset. If denied, please cite to the specific page numbers from those decisions in which the Commission explicitly stated that it was approving inclusion of the pension asset in rate base as a regulatory asset.

Response: Regulatory assets (overfunded) and liabilities (underfunded) for pension benefits have been included in the Company's rate base since at least 2005 (Decision No. 67744 dated April 7, 2005) as evidenced by their inclusion in Standard Filing Requirement Schedule B-1 and itemized in Schedule B-1 workpapers. B-1 was sponsored by APS witness Bill Post.

Although not explicitly addressed in each of the Decisions mentioned in the Company's response to AECC 10.1(b), the pension asset is an investment in APS's employees and therefore treated in rate base in the same manner as other investments, such as a distribution substation or generating plant.

As part of a rate case, Staff and intervenors review the Company's revenue and expense as set forth in its Standard Filing Requirements through the discovery process and propose adjustments for the Commission's consideration based on their individual reviews. The fact that there is no discussion in these decisions regarding a pension asset or liability shows that this treatment of pension expense is accepted ratemaking practice.

Witness: Elizabeth Blankenship

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
THIRTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
MARCH 26, 2020

AECC 13.8: **Pension Asset**. Please refer to APS's response to AECC 10.1(b), which contends that Commission precedents allow APS to include the pension asset in rate base as a regulatory asset according to Decision Nos. 69663, 71448, 73183 and 76295. Admit that there is no prefiled testimony in the record of any the dockets of the cited decisions in which APS seeks approval of the inclusion of the pension asset in rate base. If denied, please identify the specific witness and page numbers of the testimony.

Response: Please see the Company's response to AECC 13.7.

Witness: Elizabeth Blankenship

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
THIRTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
MARCH 26, 2020

AECC 13.9: **Pension Asset**. Please refer to APS's response to AECC 10.1(b), which contends that Commission precedents allow APS to include the pension asset in rate base as a regulatory asset according to Decision Nos. 69663, 71448, 73183 and 76295. Admit that there is no prefiled testimony in the record of any the dockets of the cited decisions in which an APS witness discusses the inclusion of the pension asset in rate base. If denied, please identify the specific witness and page numbers of the testimony.

Response: Please see the Company's response to AECC 13.7.

Witness: Elizabeth Blankenship

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
SIXTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
APRIL 6, 2020

AECC 16.1: **Cash Incentive.**

a. Please refer to APS's supplemental response to AECC 6.1 a. Please provide the breakout of the 2019 cash incentive dollars that were used to calculate the Test Year cash incentive between Company Performance and Business Performance, as APS provided for 2017 and 2018.

b. Please provide the derivation of the Test Year cash incentive using the 2018 and 2019 cash incentive amounts.

Response:

a. Please see the table below.

	Company Performance	Business Performance	Total
	(dollars in thousands)		
July-December 2018	$ 9,796	$ 12,606	$ 22,401
January-June 2019	$ 3,708	$ 12,370	$ 16,079
	$ 13,504	$ 24,976	$ 38,480

b. APS utilized the amounts reported in APS's Initial Data Request 15. Using the percentages contained therein, 58.2% of the costs are related to 2018 and 41.8% of the costs are related to 2019.

Witness: Elizabeth Blankenship

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
SIXTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
APRIL 6, 2020

AECC 16.2: **Cash Incentive.** Please refer to APS's response to AECC 6.1 b. Please provide the average proportion of the Shareholder Value performance level to the total Business Unit Performance for the actual 2017, 2018, and 2019 cash incentives. For an example of the requested information, please see APS's response to AECC 6.1 b. in Docket No. E-01345A-19-0236:

> "b. Each Business Unit Performance plan contains a Shareholder Value component. Depending on the business unit the Shareholder Value components may be based on that business unit's O&M budget and/or capital budget. The performance level of the Shareholder Value metric varies across each business unit. On average, the proportion of the Shareholder Value performance level to the total Business Unit Performance is approximately 28% for 2013, 22% for 2014, and 28% for 2015. Please see Pre-filed 1.47 for business unit plan result for 2014 and 2015. Please see EFCA 12.3 for 2016 plan results."

Response: Each Business Unit Performance plan contains a Shareholder Value component. Depending on the business unit, the Shareholder Value components may be based on that business unit's O&M budget, capital budget, net operating expense, and/or value based maintenance savings. Although these components have been labeled as "Shareholder Value" in APS's incentive plan, they in fact provide equal if not greater value to APS customers.

The performance level of the Shareholder Value metric varies across each business unit. On average, the proportion of the Shareholder Value performance level to the total Business Unit Performance is approximately 28% for 2017, 22% for 2018, and 25% for 2019.

Witness: Elizabeth Blankenship

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
EIGHTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
APRIL 21, 2020

AECC 18.1: **Customer Counts.** Please provide the number of customers in each of the rate schedules shown in the table below and on a total retail basis as of December 31, 2019, in Excel format. Please specify whether the Non-Residential customer counts corresponding to column (b) of the table below are inclusive or exclusive of the Irrigation customer counts in column (d). If APS contends it does not know the number of customers by rate schedule as of December 31, 2019, please explain why APS does not have this information.

(a)	(b)	(c)	(d)
Residential	**Non-Residential (Non-AG-X)**	**AG-X**	**Irrigation**
E-12	E-20	E-32 M	E-30
ET-1	E-30	E-32 L	E-32 XS
ET-2	E-32 XS	E-32TOUL	E-32TOU XS
ECT-1R	TPEAK	E-34	E-32 S
ECT-2	E-32 XSD	E-35	E-32 M
ET-EV	E-32 S		E-221
R-XS	E-32 M		
R-BASIC	E-32 L		
R-BASICL	E-32TXS		
R-TOU-E	E-32TOUS		
R-2	E-32TOUM		
R-3	E-32TOUL		
R-TECH	GS-SCHM		
E-12 EPR-2,6	GS-SCHL		
ET-1 EPR-2,6	E-34		
ET-2 EPR-2,6	E-35		
ECT-1R EPR-2,6	E-36 XL		
ECT-2 EPR-2,6	E-221		
ET-SP EPR-2,6	E-221-8T		
ET-EV EPR-2,6	GPS		
R-BASICL EPR-2,6	HLF-1		
R-TECH EPR-2,6	HLF-2		
ET-SP RCP	HLF-3		
ET-EV RCP	XHLF		
R-BASIC RCP	CNTRCT12		
R-BASICL RCP	E-58		
R-TOU-E RCP	E-59		
R-2 RCP	E-67		
R-3 RCP	E-47		
R-TECH RCP			
E-47			
Green Power			

Witness: Jessica Hobbick
Page 1 of 2

Response: The information is provided as attachment ExcelAPS19RC01262. The non-residential count does not include the irrigation customers.

Witness: Jessica Hobbick

AECC 18.1 Customer Count

	Dec
R-XS	286,832
R-BASIC	107,138
R-BASICL	32,541
R-TOU-E	361,299
R-2	74,954
R-3	179,325
R-TECH	23
E-12 EPR-2,6	29,680
ET-1 EPR-2,6	9,223
ET-2 EPR-2,6	34,134
ECT-1R EPR-2,6	367
ECT-2 EPR-2,6	2,082
ET-SP EPR-2,6	-
ET-EV EPR-2,6	-
R-BASICL EPR-2,6	-
R-TECH EPR-2,6	-
ET-SP RCP	-
ET-EV RCP	-
R-BASIC RCP	-
R-BASICL RCP	-
R-TOU-E RCP	16,831
R-2 RCP	2,397
R-3 RCP	3,740
R-TECH RCP	31
E-47	-
Green Power	-
Total Residential	**1,140,597**

Non-Residential (Excludes AG-X and Irrigation)	Dec
E-20	396
E-30	4,288
E-32 XS	103,491
E-32 XSD	951
E-32 S	19,226
E-32 M	4,232
E-32 L	811
E-32TXS	537
E-32TOUS	167
E-32TOUM	80
E-32TOUL	63
GS-SCHM	195
GS-SCHL	52
E-34	17
E-35	33
E-36 XL	5
E-221	1,187
E-221-8T	45
CNTRCT12	43
E-58	743
E-59	376
E-67	155
E-47	-
HLF	5
Total	**137,098**

AG-X	
E-32 M AG-X	16
E-32 L AG-X	89
E-32 TOU L AG-X	1
E-34 AG-X	2
E-35 AG-X	7
Total AG-X	**115**

Special Contracts	5
Total Customers	5

Irrigation	
E-221	55
E-221-8T	5
E-30	24
E-32 M	2
E-32 S	8
E-32 XS	265
Total Irrigation	**359**

Total Retail Count	1,278,174

FREEPORT MINERALS AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S TWENTY THIRD SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 21, 2020

AECC 23.2: **AG-X.** APS's proof of revenue shows APS's proposed revenue requirement being recovered through proposed rates, including AG-X rates. If APS's proposed rates were approved, does APS agree that the provision in the Power Supply Adjustment (PSA) Plan of Administration (POA) that excludes $1,250,000 month from the PSA would no longer be necessary after the rate effective date? If so, does APS intend to eliminate that provision from its proposed PSA POA? If not, please explain why APS believes this PSA provision should continue.

Response: This pro forma adjustment was mistakenly left out of the calculation of the revenue requirement. APS will correct this in a supplement to Staff 5.7.

Witness: Leland Snook

FREEPORT MINERALS AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S TWENTY FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 AUGUST 24, 2020

AECC 24.1: **SEBRP Cost.** Please refer to APS's response to Data Request AECC 15.2. In its response, APS stated it would provide updated estimates when it receives the mid-year valuation report from its actuary. Please provide an estimate of the following components of the 2020 SEBRP cost provided in APS's supplemental response to AECC 15.1, Attachment APS19RC01554:

a. Service Cost,

b. Non-Service Cost w/o SEBRP PNW and OPEB ROA,

c. PNW SEBRP Non-Service Cost.

Response: Please see attachment ExcelAPS19RC02051 for the requested information.

Witness: Elizabeth Blankenship

Summary for the six month period ended June 30, 2020

	6/30/2020 Pension	6/30/2020 SEBRP	6/30/2020 Other Benefits
APS Net Periodic Service Cost Expensed	13,160,873	439,781	5,378,212
APS Net Periodic Non-Service Credit excluding OPEB ROA	(16,304,231)	3,473,329	(4,192,763)
OPEB ROA	-	-	(11,659,034)
APS share of costs charged to expense	**(3,143,358)**	**3,913,110**	**(10,473,585)**

	Jan - Jun 2020 Benefits Cost (Towers Report)			
	Pension	**SEBRP**	**OPEB**	**Total**
Service Cost	27,207,126	909,148	11,118,237	39,234,511
Non-Service Cost:				
Non-Service Cost w/o SEBRP PNW and OPEB ROA	(22,783,746)	4,853,675	(5,859,022)	(23,789,093)
Non-Service Cost Percentage w/o SEBRP PNW and OPEB ROA	96%	-20%	25%	100%
PNW SEBRP Non-Service Cost	-	798,020	-	798,020
OPEB ROA	-	-	(20,038,434)	(20,038,434)
Total (ties to Towers total cost divided by 2)	4,423,380	6,560,843	(14,779,219)	(3,794,996)

APS Share of Total Service Cost	99.55%
APS Service Cost O&M%	48.59%
APS Non-Service Credit w/o SEBRP PNW and OPEB ROA	$ (17,023,665)
APS Non-Service OPEB ROA	$ (11,659,034)
Total Non-Service Credit Expensed	$ (28,682,699)

	Jan - Jun 2020		
APS Expense	**Pension**	**SEBRP**	**OPEB**
Service Cost O&M	13,160,873	439,781	5,378,212
Non-Service Credit Excluding SEBRP PNW and OPEB ROA	(16,304,231)	3,473,329	(4,192,763)
OPEB ROA	-	-	(11,659,034)
Amt charged to APS exp.	**(3,143,358)**	**3,913,110**	**(10,473,585)**

ARIZONA CORPORATION COMMISSION STAFF'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 27, 2020

Staff 5.7: **Errors**. As the Company discovers errors in its filing, identify such errors and provide documentation to support any changes. Please update this response as additional information becomes available.

Response:

Number	*Item*	*Description*
1	Cost Allocation	Allocate Four Corners deferral income statement and rate base pro forma to all ACC
2	Miscellaneous/Out of period pro forma	Add removal of $700k of Bain costs
3	WP 4 Disallowance adjustment	Change needed, described in APS's response to AECC 2.2
4	OMP & 4C SCR deferral	Change needed, described in APS's response to AECC 2.3 - debt return amounts were not accurate due to incorrect tax depreciation rates
5	Cost Allocation	Allocate retired power plant deferred taxes to total system benefits, not retail system benefits
6	Cost Allocation	Reg assets and liabilities
7	Base Fuel Pro Forma	Adjust sales in base fuel pro forma to account for customer annualization
8	Crisis Bill Pro Forma	Incorrectly categorized as revenue, not expense
9	Load Research	Update sales amounts for AGX, E-32M and L-TOU, and non-TOU, which are currently overstated

Supplemental Response:

10	AG-X Charges	See APS's response to Calpine 1.1
11	Transmission Expense	Expense for March 2019 was omitted from model, however, transmission revenues for March were included, resulting in an understatement of revenue requirement

Second Supplemental Response:

12	Updated Allocation Factors and COSS Model	See APS's response and supplemental response to AECC 19.11

Third Supplemental Response:

Upon further review, items 5 and 6 above have been determined not to be erroneous.

13	Minor differences in generation level energy for non-AG-X customers between tabs	See APS's response to AECC 21.8

Please also see the table below for additional workpapers for several errors listed above:

Number	Item	Attachment
2	Miscellaneous/Out of period pro forma update	ExcelAPS19RC01637
3	WP 4 Disallowance pro forma update	ExcelAPS19RC01636
4	OMP deferral pro forma update	ExcelAPS19RC01641
4	4C SCR deferral pro forma update	ExcelAPS19RC01640

APS is still analyzing the COSS impacts from the above errors and will provide that information as soon as it is available.

Fourth Supplemental Response:

Please see the table below for additional workpapers for the rate base impacts for several errors listed above. The attachments provided in the 3rd supplemental response above are the income statement impacts (as the file names state).

Fourth Supplemental Response to Staff 5.7 (continued):

Number	Item	Attachment
3	WP 4 Disallowance pro forma update	ExcelAPS19RC01648
4	OMP deferral pro forma update	ExcelAPS19RC01644
4	4C SCR deferral pro forma update	ExcelAPS19RC01643

Please also see attachment APS19RC01679 for the COSS impacts of the above-mentioned errors, except error 14 above. This includes the fixes for the errors referenced in AECC 19.11 and AECC 21.5.

Fifth Supplemental Response:

Number	*Item*	*Description*	*Estimated Impact*
14	E-32 Storage Pilot in POR	This rate mistakenly had charges left blank in the "Proposed" tab of the POR, but the rates are correctly displayed on the E-32L tab	No impact on revenue request
15	AG-X PSA Provision	Please see the Company's response to AECC 23.2	Reduction of $15M in the revenue request

Sixth Supplemental Response:

Number	*Item*	*Description*	*Estimated Impact*
16	RCND Study	As noted in RUCO 6.10, APS identified an error in the initial RCND study. An updated study was provided in the supplemental response to RUCO 6.10	Reduction of $2M in the revenue request

Please also see attachment ExcelAPS19RC02085 for an updated COSS study (that builds on the corrections made in APS19RC01679) which includes the impacts of error 15 and 16 above. This attachment also includes the update from Staff 15.3 to include actuals from the 12-month PTYP period. Please also see attachment APS19RC02086 for the updated allocation factor report and the allocation factor workpaper ExcelAPS19RC02102.

EXHIBIT KCH-16
(Confidential)

Exhibit Intentionally Omitted - Contains Confidential Information